COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Summer 2005 Electricity Supply	)	Docket No.
and Demand Outlook	)	05-SDO-1
	)	
__________________________________	)	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, MARCH 21, 2005

9:03 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Associate Member

Jackalyne Pfannenstiel, Vice Chairperson

STAFF and ADVISORS PRESENT

Melissa Jones, Advisor

Mike Smith, Advisor

Timothy Tutt, Advisor

Scott Tomashefsky, Advisor

David Ashuckian

Lynn Marshall

Tom Gorin

Denny Brown

Jim Woodward

ALSO PRESENT

Steven Kelly
Independent Energy Producers Association

Art Canning
Southern California Edison Company

Ron Calvert
California Independent System Operator

Richard Aslin
Pacific Gas and Electric Company

William Tom
Pacific Gas and Electric Company

John Schumann
CADWP

ALSO PRESENT

Robert Anderson
San Diego Gas and Electric

Gary Schoonyan
Southern California Edison Company

Tim Vonder
San Diego Gas and Electric Company

Josh Bode, Student
University of California Berkeley

Bruce Kaneshiro
California Public Utilities Commission

Kevin Woodruff
The Utility Reform Network

I N D E X

I N D E X

P R O C E E D I N G S

9:03 a.m.

ASSOCIATE MEMBER GEESMAN: This is a Committee workshop of the California Energy Commission's Electricity Committee. My name is John Geesman; I am the Associate Member of that Committee. Commissioner Keese, who is the Presiding Member, is unable to join us today.

To my immediate left is Commissioner Pfannenstiel, the Commission's Vice Chair. To her left is Scott Tomashefsky, Commissioner Keese's Advisor. To my right, Melissa Jones, my Staff Advisor; and to her right, Mike Smith, Commissioner Boyd's Staff Advisor.

The purpose of today's workshop is to try to provide a public review of our staff's projection of the electricity supply and demand outlook for the summer of 2005. As well as to provide a similarly public review of the projections of the utilities, the ISO and others. This subject has received a great deal of attention since projections started being made late last summer of potential problems in southern California this coming summer.

One of the peculiar charms of the

Commission's structure of government is that we do have an independent staff, but we have the mechanism, and in fact responsibility from time to tome, to try and provide a public forum for the review of staff work products.

I want to thank Senator Dunn for pointing that out to our Executive Director in a hearing of Senate Public Utilities and Energy Committee a couple of weeks ago. And our Executive Director indicated that this would be an appropriate subject for such a vetting. So here we are.

We're going to start with some remarks from Dave Ashuckian from our staff.

MR. ASHUCKIAN: Good morning and welcome to our workshop on the summer outlook. And as Chairman Geesman mentioned, this is to basically have a public vetting of some of the numbers that we are projecting in what we're calling a projected outlook.

What I'm going to do is provide an overview of today's agenda, as well as how we created the outlook. And then a brief discussion about the difference between what our projected operating reserves are compared to what we call planning reserves. And that again compared to what is the actual operating reserve.

We have a call-in number for those -- it sounds like people are already on the conference call. We'll also, after I'm talking -- for those of you on the conference call, if you could do me a favor and press your mute button until you are ready to speak, that way we won't hear any background noise from the call feedback.

Again, the purpose of our workshop is to explain how we created this outlook; also to go into more detail on the weather-adjusted -- the methodology for the one-in-ten, as well as the one-in-two demand.

And then we've asked other parties, including the utilities, to present their assessments to compare with ours; as well as to have a comparison of some past forecasts with what actual data occurred to see how well forecasts have been in the past.

What we'll have is again these presentations. We will talk about the resource supply that is in our outlook. We will then go to other parties' assessments. We will also have a quick update on the hydro availability for this summer. And then open it up for comments and discussion.

We don't have a set timeline for this afternoon. Depending on how long the presentations go, we'll just identify a spot where we can take a break for lunch, if necessary, and then to on to the afternoon.

So we're not quite sure exactly how long the whole workshop will go, depending on how many questions, comments and interaction we have with the participants.

Here's the call-in information for any of those who are viewing this on webcast to call in.

We're also accepting written comments through this Friday. And if you would, the best way to do that is through email to our docket office. And please include the docket number, as indicated, 05-DSO-1. And include the title somewhere, Summer Electricity Supply and Demand Outlook.

I will start off here by talking a little bit about how we create this outlook. Staff of the Energy Commission, the ISO, PUC Staff, as well as some of the staff of the utilities that are in affected areas, have been working together over the last few months to compare our numbers, to look at supply and demand and transmission constraints. And have done our best to get a kind of a collaborative position on what we believe the outlook for supply and demand will be.

You know, obviously this is an Energy Commission product. And so we do have various policies and caveats that we place on this so that there may, in fact, not be 100 percent agreement on all the final product, but a lot of the information that goes into this have been at least reviewed by other staff.

As Commissioner Geesman mentioned, this was first presented at Senate Committee hearing on February 22nd. And basically we have committed to an annual process where we will review these outlooks and get a public vetting of our assumptions and the numbers that go into them on an annual basis.

What this outlook is is a snapshot of the physical resources and capabilities of the system in California to meet demand. It is not what is contracted by various utilities, various entities. It is only -- includes the available capacity by the first of each month. So if a power plant say comes on in the middle of the month we're not including it as being available for that month. Again, this is more of a way to impose some conservatism in our outlook.

This year we've also expanded, compared to past years, in that we are looking more closely at the northern and southern region of the ISO control area, as a result of actually last summer where there was some particular concerns about minimum reserves in the southern California or south of Path 26 region.

I want to go into a little bit now on the comparing the reserve margins. As I mentioned before, the planning reserve, which is often what people use to plan for the future, includes a 15 to 17 percent target. And many of you may have heard some of the press releases recently by some of the utilities, and even at the Senate Committee hearing, where utilities were saying that they have adequately planned and have secured contractual obligations for resources to meet their summer needs.

That may appear to contradict what this

particular outlook is saying, which is that there may be a concern in the very hot weather condition. Now, there is a difference between what we're saying and what the planning reserves are, and that is our projected operating reserves is including both the one-in-ten as well as the one-in-two outlook. And so when you look at the worst case scenario it's the one-in-ten demand that we are comparing to.

We also include expected and forced and planned outages using a standard deviation over average outages. We also are including transmission constraints that we've got from information from the ISO on the limits of deliverability to certain regions. Those are all things that are not included in a planning reserve.

And finally, we are not including the interruptible and demand response programs under the assumption that those are only going to be used in the case of an adverse condition or an extreme event.

Now you can contrast that to the actual operating reserves, and you'll find that obviously with the actual operating reserves -- this is where the control operator is actually trying to maintain the system operation -- it's based on actual weather, actual demand, actual forced and planned outages, as well as the transmission constraints that are created as a result of how individual plants are dispatched.

Again, the actual reserve margin requirement is 5 percent for hydro resources and 7 percent for thermal resources. And so the actual reserve needed to maintain a system is somewhere between 6 and 7, depending on the actual resources that are operating at the time.

Now, one thing that we really can't do is go back and compare what our expected reserve margins are compared to actual resource margins, because the system control operator is trying to maintain that 6 to 7 percent reserve. What we're showing is what we believe is an expected or possible reserve.

And so if there's actually additional reserves available in real time, they're not necessarily called upon because we don't want to have excess resources that are just operating that aren't being used.

And so you'll often, you know, find that you'll never have a operating reserve that's much larger than 7 percent. Whereas we may project, you know, a 10, 15, 20 percent reserve margin based on the resources that are available.

Actually that's the end of my part. I was going to have Lynn Marshall come up and talk about the demand forecast.

Now, one thing that I think, based on the comprehensive agenda we have, if there's questions that people have during the individual presentations I think it would be best to have questions at the end of each presentation, rather than waiting to the very end. There may be a lot of questions that are held for awhile. So, if there's any questions, feel free to ask at the end of each presentation.

ASSOCIATE MEMBER GEESMAN: Steven.

MS. MARSHALL: Okay, --

MR. KELLY: Steven Kelly with IEP. Just one quick question. I got a little confused there. In your chart showing comparing the reserve margins, I always think of the planning reserve as including kind of the 7 percent operating reserves plus the planning reserves.

And when I look at the comparison in the planning reserve you're not including deliverability constraints, which I kind of infer as being transmission constraints.

And in the projected operating reserves, you are. I'm kind of confused about how that all feeds together.

MR. ASHUCKIAN: Yeah, we believe that the current process, the planning reserves do not include deliverabiity constraints. Now, that's part of the resource adequacy process that's being developed. But right now it's our understanding that they are not included.

MR. KELLY: But are the operating reserves, kind of the resource stack down here, and then I think of the planning reserves as an add-on to that. So if you've counted it in the planning -- operating reserves, aren't you intuitively counting it in the planning reserves? How you treat it.

MR. ASHUCKIAN: I'm not sure I quite understand. The 15 percent includes what would be necessary to maintain a 7 percent operating reserve. It is not on top of that. So that it's not a 21 percent reserve.

MR. KELLY: No, I agree. So you've got,

let's say, 15 percent planning reserve that includes as part of that, I believe, a 7 percent operating reserve, right?

MR. ASHUCKIAN: I think the expectation is that a 15 percent planning reserve would allow you to maintain a 7 percent operating reserve.

MR. KELLY: And when you've calculated your operating reserve you've included transmission constraints, deliverability --

MR. ASHUCKIAN: That's correct.

MR. KELLY: -- issues?

MR. ASHUCKIAN: When we've concluded our projected operating reserve it is more like the operating reserve than the planning reserve.

MR. KELLY: I'm just confused as to why you would treat what I've called deliverability constraints in the operating reserves and not in the planning reserves. I'm confused there.

MR. ASHUCKIAN: We believe that is not a consideration when it comes to planning reserves. That actual deliverability currently is not a criteria that has to be included in developing the planning reserve.

ASSOCIATE MEMBER GEESMAN: I think, Steven, the way I interpret what Dave's saying is it's a question of precision. The planning reserve is a less precise calculation than the operating reserve. Hopefully the planning reserve includes at least 7 percent operating reserves that will, in fact, meet a deliverability test. But there's no assurance that it does.

Ultimately when you do get to calculating the operating reserves, though, they do impose a deliverability requirement, as explained to them by the ISO.

MR. KELLY: So the forecast, what we're doing here, the assessment, actually got a deliverability consideration for the 7 percent of the operating reserves, and then it's a little looser for the planning, is --

ASSOCIATE MEMBER GEESMAN: That's what he said, I believe.

MR. ASHUCKIAN: Yes.

MR. KELLY: Thank you.

MS. MARSHALL: Okay. The load projections used in this summer assessment were developed over the course of last summer and fall, specifically to support this interagency group that Dave mentioned, looking at the summer of 2005 supply/demand situation.

The last complete forecast that we produced using the CEC's demand modeling system was in March of 2003 in support of the 2003 Integrated Energy Policy Report. This chart shows a variety of our past forecasts compared to the actual line, which is the heavy dark line, the actual recorded statewide peaks.

Our last forecast was that bottom pink line. And as you can see from that we were in '03 and '04 clearly tracking a bit low. On a recorded basis it's 2, 2.5 percent. But focusing on the year-ahead numbers where we have an estimated weather-adjusted statewide peak, you can see, if you look at the bottom row, our assessment for '04. We had adjusted our demand forecast for 2004 up slightly, but we were still more than 3 percent too low.

So that suggests that the forecast we were using was not going to give a realistic estimate, specifically for the summer of 2005.

Our modeling system is designed to capture long-term trends. We're focused on a five- to ten-year outlook. They are not designed to capture short-term variation in business cycles. And indeed, the economic drivers that we were using for this last forecast under-predicted economic activity, the gross state product projections turned out to be more than 5 percent too low for 2004.

So, to support this interagency group's assessment of next summer, clearly we needed to develop something that was going to be more realistic estimate for the summer of 2005.

We are in the process of developing a new long-term demand forecast, but that's not quite prepared. So going back to last fall, we needed to come up with something else.

So here's what we did. In our demand modeling system we first forecast annual energy consumption. And from that we apply our load shapes to develop an annual peak forecast for each utility area in the state.

At this point we had two additional years of sales data; the previous forecast was based off 2001 sales data. So, we took those 2002/2003 electricity sales to develop a new annual consumption forecast. Used the load factors and the growth rates from our previous peak demand forecast. And that gave us a new projection for '04 and '05.

Then as we got to the end of the summer, we took the recorded peaks for 2004 and evaluated those compared to this new working projection that we had, to see where we were significantly off trend. In most cases it was the predicted '04 and the weather-adjusted '04 were pretty close. However, most notably for SP-15 we made an additional adjustment up, and I'll talk more about that.

So here's the additional sales data that we were using to adjust the sales and then the peak forecast up. And as you can see, for PG&E the dark bar stacked on top shows the difference between what actually occurred and what we were forecasting. And these sales are weather-adjusted. So it's less than 2 percent for PG&E.

However, for Edison almost 5 percent higher in '03 than we predicted. And again you can see southern California, LADWP, again almost 5 percent difference. Also a big increase in SMUD; and then the other area that's a lot of growth, in IID.

And you can see we're also adjusting the DWR energy. And also their peak was higher than we were assuming previously. So that was our first set of adjustments.

Then at the end of the summer we received daily peak data for the congestion zones for NP-15. And here NP-15 also includes zone path 26. So north and south daily peaks. And we used those, we have a set of about ten weather stations that we weight according to distribution of air conditioning throughout the state to estimate a weather-response function to come up with an estimate of demand under 1 and 2 are average weather conditions.

So this shows, for this chart I've normalized it to 2003. So you can see the increase from '03 to '04. And we have a temperature response of about 315 megawatts per degree. So we're using a one and two temperature of 101 degrees. And that gave us an estimated one and two demand for '04 of about 21-8, which was very close to our working projection of 21-6. So we made no further adjustments to the NP-15 forecast.

We have, since then, reduced it to account for the creation of the SMUD control area, moving Redding, Roseville and WAPA over. So that's the derivation of the NP-15 forecast.

We've got a little less than 2 percent growth up there in NP-15.

Doing the same type of analysis for SP-15, the estimated one and two at one and two temperatures was about 26,200, and that was about 1000 megawatts more than we had been projecting just using the sales data. So we made an adjustment up, essentially using about that figure as our base. And then used the growth rate from the 2003 to '13 forecast, so that gives us an SP-15 forecast of around 27,000 megawatts.

We did a similar adjustment for SMUD, which I didn't show here.

Now, as part of our 2005 IEPR most of the utilities have submitted '05 forecasts. I guess some of you will talk about your individuals, but since nobody else has the compilation of all of those forecasts, and no one else does the whole state, this is our attempt to put all those forecasts together that the LSEs have submitted to us. We're filling in the blanks of those smaller LSEs that don't submit.

So you can see, by control area, the difference between what we're projecting for the summer '05 and the aggregation of the individual utilities. And SMUD, and I think in the ISO, we end up being quite close. IID, again there's an area -- they're continuing to have very strong growth in 2004 that we've not accounted for.

But overall, statewide, they're generally pretty consistent. I think LA is the other area where we may be -- improving our weather adjustment, I think, we might resolve those differences there.

ASSOCIATE MEMBER GEESMAN: Lynn, do you think these are commonly weather-normalized across utilities?

MS. MARSHALL: Well, these are their 2005 forecasts. And I didn't -- because of that -- I didn't show the comparison of '04 because of that, because I had a lot of apples and oranges. But for 2005 I think everyone should be using a fairly consistent definition of what their one and two is.

ASSOCIATE MEMBER GEESMAN: Okay.

MS. MARSHALL: There may be some differences, but I think it's a pretty consistent set of data.

So that's all for me. Are there any questions on this?

ACTING CHAIRPERSON PFANNENSTIEL: Lynn, I --

ASSOCIATE MEMBER GEESMAN: Yeah -- go ahead.

ACTING CHAIRPERSON PFANNENSTIEL: Lynn, I just want to make sure I understand how these come about fundamentally. You do a load forecast for each entity and then apply a load factor?

MS. MARSHALL: Yes.

ACTING CHAIRPERSON PFANNENSTIEL: And do you -- are the load factors changing over time, or are you doing a consistent load factor? How are those coming about?

MS. MARSHALL: Well, in our peak model they are changing over time. This, you know, for this case we were just doing '05. In our -- normally when we're doing a long-term forecast we have a set of load shapes and we have weather adjustments and they are adjusting over time. And also the sector mix is changing over time.

So we're modeling load change for each, you know, residential, commercial within each utility area. And I think in some of those the load shape is slightly declining over time, but these are not big changes. Certainly for '05 I don't think it's a factor.

ACTING CHAIRPERSON PFANNENSTIEL: I see, and so no things like demand response programs or --

MS. MARSHALL: No.

ACTING CHAIRPERSON PFANNENSTIEL: -- other kind of consumer programs are affecting the load shapes that you're seeing?

MS. MARSHALL: Actually to the extent that we do account for things like building standards, programs that would affect air conditioning. So that would reduce the end use, the energy attributed to that end use, and therefore that would affect the load shape. So that does get factored into our long-term forecast.

ACTING CHAIRPERSON PFANNENSTIEL: Thank you.

ASSOCIATE MEMBER GEESMAN: Lynn, one of your -- in fact, I think it was your first slide, pointed out on a statewide basis not surprisingly actual demand never seems to proceed in a very straight line over time.

MS. MARSHALL: Right.

ASSOCIATE MEMBER GEESMAN: And your

second slide showed, again on a statewide basis, that for at least '02 through '04 we experienced about a 3.4 percent average variance from actual forecasts.

Have you made that calculation over a longer period of time?

MS. MARSHALL: Yeah, if you're looking at this first chart, if you look into say the three-to-eight timeframe, three-year to eight-year timeframe, the average error is around 4 percent, 4, 4.5 percent.

ASSOCIATE MEMBER GEESMAN: And have you attempted to do a similar calculation for southern California or northern California?

MS. MARSHALL: No, we haven't broken this out to that level of detail.

ASSOCIATE MEMBER GEESMAN: And do you have a sense as to whether one region might be larger or smaller in deviation than the other? It's unlikely that they're both 3.4 percent, isn't it?

MS. MARSHALL: Yeah. I don't actually have a sense of which way that might go.

ASSOCIATE MEMBER GEESMAN: I'm just trying to get a feel for how much deviation is likely to be in any of these forecasts. And at least using the numbers that you've got here it would seem that it's close to 2000 megawatts on a statewide basis. Is that a fair representation?

MS. MARSHALL: Yeah, I think so.

ASSOCIATE MEMBER GEESMAN: And you had mentioned that our forecasting tool is really not designed to calculate the next year; it's really more something that we've developed on a ten-year horizon, and then you mentioned that it's also got a five-year readout, as well.

Is the variation more or less over that ten-year horizon?

MS. MARSHALL: I think when you get past the six to eight years it does increase. So it's, in the first few years the average error is maybe 3 percent; in the mid-term it's, I think, 4, 4.5 percent; and then it's closer to 5 percent as you get farther out.

ASSOCIATE MEMBER GEESMAN: Okay. Thanks very much.

MS. MARSHALL: Okay. Any other questions?

MR. CANNING: Art Canning from Southern California Edison. Lynn, in your last slide where you look at the ISO coincident peak as reported by historical, by LSE submittals for 2005. How much of that did you have to fill in? Did you have munis you had to fill in probably, under 200 megawatts? And ESPs, is that right?

MS. MARSHALL: Well, actually for -- you had a distribution area forecast, so I used your -- Edison's total --

MR. CANNING: Oh, you did?

MS. MARSHALL: -- because that minimized the --

MR. CANNING: Oh, you did.

MS. MARSHALL: -- number of small pieces. But it's still only a few hundred megawatts of entities that we're not receiving submittals from. There's a little bit of inconsistency in comparing the components, you know, your resale cities, to your total doesn't all quite add up yet. So that I did, for this, decide to use your distribution area --

MR. CANNING: Okay.

MS. MARSHALL: -- as a basis of comparison.

MR. CANNING: Because you remember, in the resource adequacy, a lot of concern about the small entities not reporting. And I was just trying to get an idea of --

MS. MARSHALL: Yeah. We do get sales data from everyone, from virtually everyone. So that where they haven't submitted to us we do have to estimate the load factor, you know. I did have some other sources for peak demand for some of the smaller munis, so it's probably pretty close.

MR. CANNING: Thanks.

MS. MARSHALL: Anyone else before Tom Gorin is going to talk about the one-in-ten methodology? Okay.

MR. GORIN: I'm Tom Gorin from the demand analysis office. And there seems to be a lot of interest in the art work behind developing the one-in-ten weather methodology that I will try and explain.

The reason that we originally did this in the fall was there was a growing concern about reserve margins and SP-26; and there were some concerns that the previous adjustment that we made was not adequate according to some parties. The previous adjustment was done in 1999. It was kind of dated. It was as a response to 1998 westwide heat storm. And it was more focused on the WECC coincident peak for the west.

We now have more recent histories of loads and temperatures. And there was some thought that we needed a more transparent methodology. So hopefully this is more transparent. It certainly raised a few questions, and I will try and explain it.

The way we developed it, and I just particularly looked at the SP-26 region. This analysis can be done for the other regions in California. It hasn't been yet because there wasn't a question about reserve margins there.

The way that I've been working on this for the last few years after we did the heat storm study, I think it needs to be developed from the bottom up. And so I developed a relationship for SCE and SDG&E separately.

I used the FERC hourly demand data for 2003; that's the latest publicly available hourly demand data. I used NOAA weather stations. And this relationship is -- the equation for the relationship is based on June 15th through September 15th weekday afternoons. That's the peak period.

Some people look at peaks, particularly

in places like San Diego, if it's not hot the peak occurs at night or late in the evening when people go home from work. So I think the 1:00 to 6:00 p.m. peak captures the weather-driven change in loads and temperatures.

Temperature definition that was used, it was a three-day weighted maximum temperature consisting of 60 percent of the current day's maximum, 30 percent of the previous day's maximum and 10 percent of the second previous day's maximum temperature to account for heat build up for air conditioning load.

Weather stations, I used San Diego, I used Lindbergh Field. That may not be the most representative weather station for the entire San Diego service area. It happens to be the only one that has a weather history dating back to 1950.

I wanted to use -- I was looking for weather stations that had a long period of history. Because if we're looking at something like a one-in-10 or one-in-20, or one-in-40 weather event, it's probably not real useful to use 10 or 20 years.

The Edison stations are Fresno, Long Beach, Burbank and Riverside. The weighting factors were based on our estimate of residential air conditioning in the Edison region for those weather stations.

This is a depiction of the weather, the temperature and load relationship for 2003 for Edison. And you get a temperature relationship of about 287 megawatts per degree over -- for temperature over 75 degrees.

You can also see that it doesn't get warm very often down there. Or it didn't last summer. I used a linear relationship which I think is conservatively high. There's some sense, and I'll go into it later, that load tails off as the temperature gets hotter. And that load doesn't increase at as high a rate when the temperatures are in the 100 to 110 degree range.

ASSOCIATE MEMBER GEESMAN: Have you done r-squared calculations for other years?

MR. GORIN: Yes, I have.

ASSOCIATE MEMBER GEESMAN: And how does this one compare?

MR. GORIN: They're in the ballpark of that. Some are higher; some are lower. In the presentation that I put together over the weekend, which is an addendum to this, you will see that in

2001 the r-squared went way down because we had a little experiment in energy use.

ASSOCIATE MEMBER GEESMAN: I think the experiment was in market design.

(Laughter.)

MR. GORIN: That's probably true. But what I tried to do in this analysis, and it's ongoing, is try to get the best fit over a period of years, and tried to get a single temperature variable. I mean in Edison's case the lag maximum temperature seems to work best over a longer period of time.

In other years and other service territories the r-squared is higher. In San Diego the r-squared is lower because they have not as much hot weather. And it's interesting, I don't have it here, but the fit is a lot tighter for PG&E because it has more customers that are subjected to hotter weather.

San Diego, the same thing. Got hot for six days. The linear approximation might not be the best fit, but I think it's relatively adequate.

This is a depiction of the relative size of the two service areas. So the most of the load in SP-26 is driven by Edison because of its relative size.

There's another factor that I haven't presented here and that the combination of Edison and San Diego will comprise most of SP-26. That tends to get translated as southern California. That's only about 80 percent of southern California. When the translation occurs they kind of leave out LADWP and IID. So there needs to be some kind of geographical translation of what areas we're actually talking about when we define these things.

The way I calculated the annual peak weather variation I took those equations for each service area and used actual daily weather from 1950 to 2003. And created a simulated daily peak for 54 years worth of summer data. I included weekend temperatures. There's some question about whether that's a viable thing to do or not. I thought it was a conservatively high way to estimate what a one-in-ten weather year would be. It might not be, you know, specifically probabilistically accurate, but I'm not convinced that we hope it just gets hot on the weekends this summer, so.

I took the annual peak temperature is coincident with the highest combined temperatures for both -- well, it's coincident with the addition of the daily peaks for Edison and San Diego, which is not San Diego's highest peak plus Edison's highest peak. It's the relationship between the two temperatures; and when you add them together whatever comes out the highest is the peak.

This is a depiction of maximum temperature for 1950 to 2003 for both Edison and San Diego. And you can see that there's a lot of divergence in that. And you can also see that what I consider one-in-ten temperatures don't happen every ten years. There's different patterns.

If you look at 1988 in San Diego it was a really high year, much more than one-in-ten. In Edison it was a little below one-in-ten. So there's a lot of divergence in temperature in the southern California region as a whole.

These are the annual temperatures, the same annual temperatures in rank order. You see that for Edison there's a 5 degree temperature differential between the median, which I'm calling one-in-two, and the fifth highest, which is one-in-ten. But for San Diego there's a 7 degree temperature differential. That's because in San Diego it's relatively mild and it just gets hot at Lindbergh Field once in awhile. But when it's hot at Lindbergh Field it's hot in the rest of the San Diego region.

So if I used other weather stations in San Diego it may raise the median temperature and reduce the temperature differential between the one-in-two and one-in-ten.

This is the depiction of the peak variability of Edison's service area. The boxes here are a rank ordering of them. Again, the one-in-two values, the median temperature and the fifth highest is the one-in-ten. For Edison you come out with a 7 percent one-in-ten weather adjustment.

Same thing for San Diego except due to the higher variation in temperature you come out with almost the 13 percent weather adjustment.

Combining those together adds up to about 7.75 percent. Now, you know, it's probably not a fail-safe method, but I think it's a relatively one that can be copied or, you know, made better by suggestions. And people can work with it.

I did put together another presentation if I can -- I thought about some comments that I got from some of the participants, and I thought I'd put some historical perspective on some of this for some additional work that we needed done -- need to do. We have the ability to look at this from -- we will have the ability to look at this from 1993 to 2004 when the FERC data comes out in July for the utilities. We can look at it now from 1993 to 2003.

Somebody was asking me about, you know, when was the last time it was hot. Well, 1998 was the most recent heat event that we had. And that was -- the heat storm study was in response to that. I also wanted to look at the electricity crisis of 2001. And I'd already mentioned something about geographical definition.

The 1998 response in Edison was about 305 megawatts per degree. And if you can -- if this line was removed you can see that there's a tail-off of the hotter it gets the load does not increase as fast as temperature.

That is transposed or juxtaposed with

the response in 2001 where the 300 went down to 250. It appears now, the most preliminary analysis and the most recent data, that we're now back to the weather response, load response for the Edison service area that we were at in 1998. So there was a great decrease due to the energy crisis because people weren't using their air conditioning as much.

The same thing occurs in San Diego. One interesting thing about this is the top, the highest four loads are one week. The lowest lower portion is another week. So in 1998 San Diego had two heat events. And those are the kinds of things we need to look at.

In 2001 the load and temperature relationship is sort of all over the place. You have a very low r-squared. You know, if you wanted to -- and I think these are related to the changes in rate structures that were taking place in San Diego at that time, along with the energy crisis. And their response went down to 48 megawatts per degree.

So, are there any questions?

ASSOCIATE MEMBER GEESMAN: Thanks, Tom. Any questions from the audience?

MR. CANNING: Art Canning from Edison, again. I appreciate your working with my staff so much over the last few weeks to try and interpret the data. I thank you a lot for that.

One thing I noticed, on the historical data you picked 54 years and it didn't matter whether the temperature occurred on a weekday or weekend.

MR. GORIN: That's correct.

MR. CANNING: Okay. And in your regression analysis you only used weekday temperatures.

MR. GORIN: That's correct.

MR. CANNING: So you're willing to accept probablistic analysis and statistical analysis in doing your regression, but no on analyzing the probability of temperatures occurring on a weekday versus a weekend, is that -- am I interpreting you right?

MR. GORIN: Basically I think temperature's in variant to weekday.

MR. CANNING: I think so, too.

MR. GORIN: And, you know, if -- and I haven't worked this through all the way, you know, I continue to work with your staff, but it's a conservatism in the adjustment factor.

MR. CANNING: Conservativism on --

MR. GORIN: On the high side.

MR. CANNING: -- cost-wise, or on reliability-wise? You say conservatism, measured by cost or by reliability? What do you mean by conservatism?

MR. GORIN: By reliability.

MR. CANNING: Okay.

MR. GORIN: You can take each of those years and make seven years out of it, depending on what date, you know, starting June 15th on Monday through Sunday. This was a convenience factor.

You can, and I haven't really worked through what the difference would be if you just looked at each year's weekday maximum temperature. I could do that.

MR. CANNING: Yeah. There's also apparently ways to adjust probablistically using all days, but adjust for what the probablistic temperature is on a weekday.

I'll just submit that that analysis does exist. We can talk about that.

A more general question, and I guess -- is it our duty to look at a one-in-ten temperature event, or one-in-ten load event? That comes right back to the same question.

Because loads won't peak on a weekend, then if you predict a one-in-ten temperature event, you're actually creating something like a one-in-14 load event. And if you predict a one-in-ten load event, it'll be more like a one-in-seven temperature event. And the differences could be several hundred megawatts, which has cost associated with it.

So that's why I'm posing the question to Tom, and he and I have talked. So, I mean, we're not in a hostile environment. We've been working together pretty closely and I appreciate it.

MR. CANNING: No, you know, but when it gets hot the first thing anybody asks, is well, was that a one-in-ten temperature.

MR. CANNING: Yeah.

MR. GORIN: They don't worry about the load. So, but I can understand your concern. And it is a further refinement that can be done. I'm just not sure, you know. It has costs associated with it which I can appreciate. I'm not sure of the complete accuracy of any of this, including weather projections for this summer.

MR. CANNING: Another couple questions. On Lindbergh Field, and adding San Diego and Edison together. So you basically said most of the load is in Edison, but the San Diego temperature has a much much wider standard deviation.

MR. GORIN: Right.

MR. CANNING: And that would impact your one-in-ten analysis.

MR. GORIN: For the region.

MR. CANNING: For the region, yeah. So if the combined region had a higher standard deviation because we add San Diego to Edison, should the combined load increase for that be attributed to San Diego or be attributed to Edison?

They're not going to tell the region to buy it, they're going to tell somebody to buy it.

MR. GORIN: I realize that. The original question that was asked to be addressed was SP-26. I don't happen to, you know, that's like -- almost like saying, well, California. Because SP-26 is a diverse region. I mean Edison's a diverse region.

But most of the increased load --

increased deviation in load is due to increases in San Diego's deviation.

MR. CANNING: So I put that to the Commissioners, too, if the deviation is due wide, or due to San Diego, then is it appropriate to any increase that comes out of this, so assign that to San Diego rather than to Edison.

Another point about Lindbergh. You know where Lindbergh Field is?

MR. GORIN: It's on the ocean.

MR. CANNING: Yeah. At what elevation is it? Take a guess.

MR. GORIN: Ten feet.

MR. CANNING: Ten feet, okay. And surrounded on how many sides by water?

MR. GORIN: I'm assuming three.

MR. CANNING: Yeah, I'm assuming three, too. So, what percentage of the San Diego load area do you think that's representative of, based on your knowledge of San Diego?

MR. GORIN: I think it's changing. You know, I think if you got a $1.5 million house on the ocean, you're going to put an air conditioner in. And for the five days it's hot, you're going to use it. So, when it's not hot there it's not much of the load. But I think it's an increasing, that adds to the increase in the deviation there.

MR. CANNING: Okay. How about Gillespie Field, would that represent El Cajon, the inland area? I'm not a San Diego expert, but it's just that's a hotter area. Would that be a temperature station you'd consider using?

MR. GORIN: If it had data past 1980.

MR. CANNING: And you think because the data's not available for the last 20 years it would be best just to use the 50-year data off Lindbergh?

MR. GORIN: We need to figure out a way to adjust Gillespie Field to look at the temperature differentiation between Gillespie Field and Lindbergh Field to maybe get a longer history. I mean we could look at Gillespie Field, we could look at Miramar. I mean Miramar has a longer temperature history, but it's still not 50 years worth of data.

MR. CANNING: All right, another one's a little bit, maybe it's probability theory, it's beyond me. Do you think if you take one station, look at standard deviation versus taking four stations and taking a weighted average of the four, do you think the one station will probably have a wider standard deviation than taking the average of four?

MR. GORIN: It depends on where the stations are. I don't think if you took Fresno and San Francisco, if you took Fresno by itself it will have a smaller standard deviation. Maybe I didn't get the question right?

MR. CANNING: Okay, well, let's just say it this way. If you use more inland stations, along with Lindbergh, do you think the standard deviation that you've shown that's close to 13 percent would probably come down?

MR. GORIN: It'll come down, yeah.

MR. CANNING: I think that's it, thanks, Tom.

ASSOCIATE MEMBER GEESMAN: Art, I wanted to ask you, you posed a provocative question as to the one-in-ten, whether it ought to be focused on temperature or on load.

I've searched the Old Testament and haven't been able to find where one-in-ten comes from as a numerical concept. But I think that what the state, and I believe the ISO, have attempted to do is replicate historic utility practice. How does Edison see it?

MR. CANNING: Before this go-round we always used to just look at historical weekday temperatures, because that was the simplest. I didn't know probability theory real well and I hadn't pushed my staff to come up with it.

Well, once this came up, I said, well, we're going to learn it and we're going to learn it much better. So over the last month we've been working with it, and closely with Tom, too, about how you would adjust using all days in history and then adjust for the probability of about two-in-seven that's going to occur on a weekend, which is about a 30 percent chance.

And run that through the normal distribution which another question is whether this is normal distributed. And there is a method. My staff has convinced me. They've all had slightly different opinions. I've got five master-degree-plus people and they have five different approaches.

We presented it to my boss Tuesday. He's a nuclear engineer. This didn't blow by him too fast, but we were still asking questions at the end, what's the right way to do it.

But there certainly is a way to do it. And it's a -- just look in the back of a statistical textbook and probability curve of one-in-ten, the -- 1.286. You multiply that times your standard deviation, and that gives you your, and types of megawatts for (indiscernible), and that's gives you your expected temperature on a weekday, using all days in history.

And we have somebody else that thinks, ah, it's a different c score. So I need to find a math major to help me. But it seems to be quite possible, rather than just picking weekday past temperatures.

And when Edison gets up to talk I have a handout I presented, too, to go over this a little bit more.

ASSOCIATE MEMBER GEESMAN: Okay, thank you. Any other questions for Tom?

Thanks, Tom.

(Pause.)

MR. BROWN: Good morning; I'm Denny Brown from the electricity analysis office. Before I get started I'd like to thank the ISO, the PUC, as well as the individual utilities that participated in collecting and correcting data in the forecast to this point.

Today I'm going to provide a quick overview of the summer 2005 outlooks for the California statewide area, California ISO control area, and then the ISO broken down into two subregions, NP-26 and SP-26.

I'll then detail the basic assumptions that went into the resource calculations. And that will include outages, transmission limitations or transmission congestion, as well as net imports.

And because net imports potentially account for about 20 percent of California's resources, I will do a quick overview of the impact of hydro conditions in the Northwest.

And finally I will take care of some accounting issues in detailing why if you add the SP-26 and NP-26 tables together they do not equal the ISO table.

Okay, starting with the California statewide outlook, most of these outlooks were presented at a Senate hearing on February 22nd. There are a couple changes to them, and I will detail those changes as I go through the basic assumptions.

The statewide typically reaches its peak in August. Includes all California ISO utilities, as well as the LADWP control area to include Burbank and Glendale, IID, the region far north and east Sierra, and the expanded SMUD control area, which includes Redding, Roseville and Western resources and load.

On a one-in-two basis resource margins look pretty good on a statewide basis. In the one-in-ten condition we see resource margins fall below 7 percent without considering demand response or interruptible programs. But they're at levels you would probably expect during these hot weather one-in-ten conditions.

Moving to the ISO control area, again it's going to be August peaking; however, we see little variation between July and through early September. Again, on the ISO control area, one-in-two resource margins appear adequate. And if we see a one-in-ten temperature event, it may result in emergency declarations being called by the ISO.

The northern region of the California ISO, NP-26, includes all PG&E service territories, as well as northern California ISO participating municipal utilities. Typically peaks in July, but minor variation in demand between late June and early September -- or excuse me, early August.

In NP-26, this is one change from the presentation for the Senate hearing, it is the expanded SMUD control area has been removed from this table. And, again, that includes Redding, Roseville and Western.

Resource margins in NP-26 greatly exceed the WECC 7 percent requirement under both temperature scenarios. However, as we'll show in the next slide, this is critical to southern California.

Southern California includes Southern California Edison, San Diego Gas and Electric service territories, as well as the southern California ISO participating municipal utilities.

This region typically peaks in late August or early September. The ISO SP-26 table includes 3000 megawatts in the net interchange column, line 7, that is coming from NP-26. And that is why the excess in NP-26 is critical to southern California.

And, again, in southern California in a one-in-two condition resource margins appear adequate. A concern is in a one-in-ten temperature event it could result in stage two emergencies. And if the demand response interruptible programs in place are not as responsive as we'd like, it could result in a stage three.

ASSOCIATE MEMBER GEESMAN: Denny, could you elaborate upon the asterisk which appears at the bottom of each of these tables, below the footnotes?

MR. BROWN: Yes. That's representative of the resource margins for one-in-two and one-in-ten. That is the uncertainty of net interchange. The net interchange, as I'll discuss in a moment, is a measure flow that the ISO has experienced. And then it's adjusted for some transmission improvements that have taken place over the last year.

Forced outages, I'll also elaborate on that a little bit when I get to line five, and show why there's significant variation in the forced outages.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. BROWN: Okay, moving to the resource assumptions, line 1, existing generation. This represents the generation that was online as of August 1, 2004. To note in the ISO SP-26 region there's 1080 megawatts included for Mexico generation that is under contract to the ISO, or ISO service utilities. And it also includes a portion for Mojave, even though it's in southern Nevada. It includes the SCEE ownership portion as an existing resource. The LADWP portion of Mojave is included under non-California ISO municipal utilities.

Also of note on the non-California ISO, it includes thermal, pump storage and hydro resources.

The additions in the table were pretty straightforward. I would like to mention a couple of them in particular. The first one is with the asterisk by it, restart mothballed plants, 175 megawatts. These resources were identified by Edison at the Senate hearings on the 22nd. And I highlight these because they were not included in our previous forecast. We've added them for this version.

And the second plant I'd like to point out is Magnolia. That is a southern California public power authority project physically located within the LA control area. So in this table we include the ISO municipal utility ownership share of that plant. The rest of the addition would be considered in LA's control area.

Moving to the retirements, the difference between known and high risk. High-risk retirements represent plants that staff feels could come back online, return to service if they had financial incentive to do so. The known plants are the ones that we believe are too -- it would be too costly to return those to service to make it economically feasible.

Okay, moving into forced outages. I'm going to use the SP-26 chart to represent our methodology for forced outages. This chart represents the 90 summer days for 2003 and the 90 summer days for 2004 resulting in 180 data points.

They're then ordered by highest demand days to lowest demand days. And that peak demand is represented by the dark blue downward sloping line.

-- days corresponding outages are represented by a triangle in the scattergram. As you can see, there's a great amount of variation in outages each day. Staff calculated what the average outage was and then added one standard deviation to account for much of this variation. And that's represented by the blue line.

In addition to the standard deviation there's a small amount of planned or scheduled outages, and we've included that difference between the blue and the red line to come up with a forecast outage represented by the red line.

ASSOCIATE MEMBER GEESMAN: Do you want to walk through again what each of the triangles represents?

MR. BROWN: Each triangle is the amount of SP-26 generation that was forced out on the day of that peak demand represented by the blue downward sloping line. So there's 180 triangles representing the daily outages for the two-year period.

ASSOCIATE MEMBER GEESMAN: Okay, this is a two-year period. And which two years?

MR. BROWN: 2003, 2004, June 15th through September 15th.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. BROWN: Okay, moving to line 6, the zonal transmission limitations. This represents capacity that is contained in line 1 existing generation but is unable to serve load due to transmission constraints.

The majority of this constraint comes from -- or this limitation comes from the 1080 megawatts of Mexico generation that cannot be delivered into the ISO control area.

To calculate, this is an ISO-provided estimate, and to calculate it they used 2004 actual meter data as a baseline, and then added net gains from the transmission upgrades to then reduce that limitation.

ASSOCIATE MEMBER GEESMAN: And when you say most of the 1080, how much do you mean by most?

MR. BROWN: That would actually be most of the 800 of the congestion. Let me go back up to the --

ASSOCIATE MEMBER GEESMAN: Okay, so what's left that is not the interconnection with Mexico?

MR. BROWN: I'm afraid I'd have to defer to the ISO on that, --

ASSOCIATE MEMBER GEESMAN: Okay. Well, they'll come up later.

MR. BROWN: Yeah. Okay, discussing line

7, the net interchange. This is imports minus exports to give the net number. It's based on California ISO metered data.

2005 increases over 2004 metered data that are included is the return of the Pacific DC line for 500 megawatts. Path 26 upgrades for 300 megawatts. And upgrades at Miguel for 400 megawatts.

And, again, here we see the Path 26 on the SP interchange shows 3000 megawatts. However, this is not taken out of NP-26 due to peak diversity and independent -- we wanted to do an independent study of the two regions.

Also of note is the LADWP 1000 megawatts of import. This is the LADWP control area, not necessarily the utility. There is a portion of LADWP's excess that they've made public in the Senate hearings. There's also a portion for the California ISO municipal owned portion of Intermountain Power in Utah.

ASSOCIATE MEMBER GEESMAN: How much is that?

MR. BROWN: It's approximately 710 megawatts.

Also on the net interchange, we're

counting 4000 megawatts of northwest import into NP-26, and another 2000 coming down the DC line for a total of 6000 megawatts.

I wanted to show the impact of dry hydro conditions in the northwest on the ability for the northwest to deliver the 6000 megawatts. The lines on this chart represent the five wettest years as the top light-blue shaded line. The middle 40 years -- this is 50 years, I'm sorry, 50 years of data between 1929 and 1978.

So the charcoal line is the middle 40. The dark blue line is the worst, the driest five years. And then the driest year of that period, 1937 is highlighted in the light blue dotted line -- dashed line.

And I wanted to show this because as you see during the summer peak there's not that much variation in capacity that can come out of the northwest between the wettest year on record or the driest year on record. There's significant energy that will be lost; and there's significant impacts during winter months.

This surplus is based on BPA's whitebook. And I've put the red line in to show the 6000 megawatts of capacity. BPA includes in their calculation approximately 1350 megawatts of contracted generation as a requirement. So that would reduce that 6000 megawatts to 4650 is all that would be required to fill the lines to capacity.

In speaking with the Northwest Council they also feel that the dry hydro conditions will not impact the ability of the northwest to fill the tielines. They are far more concerned with the Fish and Wildlife Service's biological opinion which accounts for about 1000 megawatts calculated by John Fazio of the Northwest Council. And that is not taken into account in BPA's loads and resources study.

ASSOCIATE MEMBER GEESMAN: So in your outlook would that reduce 6000 to 5000?

MR. BROWN: I put the red line in here represents 6000. That 1000 would -- there's also 1350 megawatts of contracted generation that would more than offset that.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. BROWN: And, again, dry hydro conditions and biological opinion does not appear that it will affect us at peak, will affect the capacity coming in. It will have significant impacts on energy coming into California.

And finally I just wanted to clear up some accounting and discuss the difference, why NP-26 and SP-26 do not add up to the ISO. The first two columns, the SP-26 and NP-26 are straight off of the respective tables for the month of August. The next column is simply adding those two up. And then the fourth column is the ISO forecast. And finally in bold is the difference between the two.

As I already discussed, the 3000 megawatts of net interchange between NP-26 and SP-26, that's accounted for in SP's table but not in NP's. There's also 600 megawatts on one-in-ten -- well, there's 561 in one-in-two of coincidents factor, load diversity factors. And 600 megawatts in a one-in-ten scenario.

The bottom line, line 13, what does it take to meet a 7 percent reserve in a one-in-ten. There's 2358 megawatts difference. So when we calculate back in the 3000 from the NP to SP-15, we have a difference of 642 megawatts. The load diversity is 600 megawatts. We're down to 42 megawatts, and that 42 megawatts represents the 7 percent reserve margin required for the 600 megawatts to make the two tables even -- three tables even out.

ASSOCIATE MEMBER GEESMAN: I wasn't clear on your retirements discussion, Denny, where Morro Bay ended up.

MR. BROWN: Morro Bay is listed as a high-risk retirement in northern California, NP-26.

ASSOCIATE MEMBER GEESMAN: Aren't those the units that just announced a contract with PG&E?

MR. BROWN: Our understanding was Morro Bay, as well as Pittsburg, in a press release they were discussing contracts. We had not received word that those were finalized yet.

ASSOCIATE MEMBER GEESMAN: Okay. Other questions for Denny?

MR. BROWN: Thanks a lot.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. ASHUCKIAN: At this point in the agenda we're asking other parties to come up and present their information on either the outlook and/or comparing previous forecasts. And I'd like to start with Ron Calvert of the ISO. He doesn't have a formal electronic slides, so he'll just say a few words.

MR. CALVERT: Good morning; my name's Ron Calvert; I'm with California ISO. I'm the Manager in Operations Engineering and Maintenance, the Load and Resources Group. I apologize for not having a soft-copy presentation to display. There are hard copy handouts on the back table. So I'll keep it kind of short and simple.

The ISO is preparing their 2005 summary assessment for operations. It will be presented to our ISO Board of Governors on March 31st. It's currently not available. Probably if we follow the standard schedule, it will probably be posted on the ISO website this Friday.

I can tell you that it's in generally good agreement with the CEC numbers, both in load forecasts one-in-two, one-in-ten; and in the total resource picture for the ISO control area, northern California and southern California.

So in the end we take two different approaches, two independent approaches, but we end up with essentially the same bottomline, within a couple hundred megawatts.

I guess I feel compelled to put in a reminder or word of caution. One thing that I've seen is people do take the numbers -- they are good estimates, they are generally indicative of the state of the system or the conditions that we're going to see. I always hesitate because I feel that people take the numbers way too literally.

It is a forecast; it is a theoretical stackup of the numbers to see how things will play out. But in real-time operations there are variations and inefficiencies of the real world system where the numbers don't coast out to exactly what was forecasted. The forecast, by definition, is somewhat wrong.

For example, the resource margins that you see are often referred to as operating reserves. You assume that you can get all that capacity in ten minutes. You're making certain underlying assumptions about the availability of ramp rates and the units that are committed and dispatched online at that time.

There's a certain allowable tolerance for deviation in real time of unreported derates or capacity that's not accounted for. These types of real world realities on a system this size can consume hundreds of megawatts. So even if your assessment or our assessment coasts out and says there's a 500 megawatt surplus at the end of the day, I'm inclined to believe that we could potentially hit that wall before it reaches zero. So, just a word of caution.

I think there's probably still a little bit of churn left in the numbers, and working through the assumptions of 2005. But I'm really anxious to get on with 2006. I know that seems early; we haven't even started summer 2005 yet but looking ahead in 2006 there's only a couple major southern California generation projects on the books. There's not that many transmission fixes on the books for another year of load growth. And there's some big retirements on the horizon.

So I'm starting to worry about 2006 and I'd like to get a jump on it and get started on that pretty soon here. And start running the forecasts and the numbers for 2006.

That's about it.

ASSOCIATE MEMBER GEESMAN: I see in the table it actually says prepared by Gary Klein, so I'm not certain that it's your table. It says, summary, ISO forecasted peaks versus actual.

MR. CALVERT: Actually that is correct;

I have a Gary Klein, too.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. CALVERT: Gary Klein is one of my engineers in the load and resources group.

ASSOCIATE MEMBER GEESMAN: They work pretty well, don't they?

MR. CALVERT: Yes.

ASSOCIATE MEMBER GEESMAN: I note, though, that historically just to re-emphasize the point you just made, your forecast with the exception of 2003 hasn't exactly perfectly captured actual experience.

MR. CALVERT: That's correct; we've guessed high and we've guessed low.

ASSOCIATE MEMBER GEESMAN: I see earlier in your presentation Lynn Marshall had indicated that our forecast over the last several years has averaged about 3.4 percent deviation. I don't know what yours would average simply because you do have a pretty large outlyer there in 2001.

But it strikes me that the level of precision in any of these projections is going to be plus or minus 2 or 3 percent. Would you agree with that?

MR. CALVERT: Yeah, I would.

ASSOCIATE MEMBER GEESMAN: And the methodology you use in developing your forecast, I'm going to guess, is quite a bit different than ours. We've always been focused on a ten-year horizon because originally the tool was intended to make need determinations for utility-sponsored power plants.

But you guys, I would presume, are focused on a much closer horizon?

MR. CALVERT: Yeah, we tend to focus or zero in on the coming season or one year out. We do do longer term forecasts; we're required to do that for reporting purposes. But our emphasis and focus is really trying to hit that next season.

ASSOCIATE MEMBER GEESMAN: Thank you. Other questions for Ron? Great, thanks a lot.

Dave, who's next?

MR. ASHUCKIAN: Next up we have Rick Aslin from PG&E. After that we'd like to ask John Schumann to come up and talk for Southern California Edison (sic). Followed by San Diego Gas and Electric.

MR. ASLIN: Good morning; my name is Rick Aslin and I work for Pacific Gas and Electric Company. We're going to give just a short presentation here on PG&E's review of the 2005 summer assessment that was done and the draft that we saw from last week.

I'm going to talk about the demand forecasting side; and then I believe Bill Tom will talk a little bit about the resource side.

Before I start I would like to extend thanks to Lynn Marshall, Tom Gorin and all of the CEC Staff who are working so closely with us, and being so easy to work with to try to come to resolution on what the best overall forecast is. So I just want to say that and hope that that carries through into the more long-term planning that we're going to be talking about over the next several months.

So what you can see here is just a comparison of PG&E's internal forecast with the CEC's forecast that was in the draft report, and also I believe that's still the same forecast that we're looking at today.

And what you can see is that in both the one-in-two and the one-in-ten cases PG&E's forecast and the CEC's forecast for summer peak for 2005 is very very close. And these forecasts are developed through very independent modeling efforts. So I think just chiming in with some other parties, especially the ISO, PG&E doesn't have any real difficulties with the idea that the summer peak for the so-called NP-26 part of the ISO zone is going to be somewhere around 21,000 to 21,5000 megawatts.

On the agenda there was a desire to discuss, at least to some extent, whether adjustment methodologies, and so I put together the slide for that. I apologize for there being so many bullets on the slide, but I think we can work through them pretty quickly.

PG&E does use a regression model to forecast its peak load. And in that regression model we're using monthly data, we're using only the peak observations for those months, and we're using ten years of data from 1994 through 2004.

In terms of driving our temperature statistics for the one-in-two and the one-in-ten we are using 45 years of temperature data. And we are using that irrespective of weekday, weekend. But we're open to suggestion on that one.

So, for the one-in-two forecast what we do is we simulate our estimated model over the average highest temperature over that 45-year period. We do have for all the months except for July and August. For July and August, in order to be conservative in the resource adequacy area, we, instead of using the average highest temperature for July and August, we actually use the average highest temperature for the year and we just impose that on July and August. Because in our service territory, if you look back through the history, you'll see that there's a roughly equal probability that the actual peak occurs in July or August. And previously we had many discussions internally about whether the peak should be in July or the peak should be in August. And so I just decided to make it both.

So when we go to the one-in-ten scenario we simply take the model that we estimated from the historical data and we simulate that over the temperature statistic of a one-in-ten temperature event, which is chosen in such a way that it should not likely be exceeded more than once, on average, in any ten-year period.

But since we've had weather for time immemorial, on average is a pretty general statement. But we chose this temperature statistic, I think, very much along the same lines that the CEC chose their temperature statistic, using the same type of methodology.

We did not use a probability distribution to do it. Simply looked at the 45 years of data that we had and we counted down, chose the number. But I can't answer the question, I think, about whether temperature is normally distributed, because we have looked at that quite a bit. We did look at alternative methodologies for choosing one-in-ten, one-in-five, so on and so forth.

And at the extreme values of temperature it's clearly not normally distributed. There's much more likely chance that you will observe a temperature which is far below the expected value than you will find a temperature that's far above the expected value.

One thing I do think we should give some consideration to, and this goes to the question of how much forecast error there is even in the expected value, is that once we get out to the extreme values, one-in-ten, and so on and so forth, we really don't know what the error is on those forecasts because we really haven't experienced those events often enough to make any real statement about what the error would be on the one-in-ten type of forecast.

And I think there is -- there seems to be some groundswell in places where people want to look at the more extreme values in terms of trying to do planning of the more extreme values. But that is one thing that I believe we should all take into consideration, is that as much error as there might be in the expected value forecasts, that amount of error in the extreme values is much higher, or could be much higher.

And just to point that out, I would agree with Mr. Gorin that in the last time PG&E's service territory had a one-in-ten event was 1998. And previous to that I believe it was 1983.

So in the last 25 years we've only had two one-in-ten events. And a lot has changed over that 25 years in terms of response of customers to temperatures, so on and so forth.

I could go ahead and talk about our kind of historical forecast error, or I could go over to Bill Tom, because I think the next slide is on supply and demand. But I think I'll go forward a couple slides if I may, and just finish up with this.

Another question that was on the agenda for the demand forecasting part of it was what was your historical forecast error. And I have to say that there was a significant period of time after the onset or advent of deregulation, reregulation, different regulation, that we did not do a peak load forecast.

Traditionally we had done those forecasts for the ER filings, and we had also done them for the -- we had this California Public Utilities Commission filings, the ECAC filings. So we had done them for that.

Both of those things sort of were on hiatus during the electric industry restructuring. And so we developed the model that we're using now after the energy crisis for the purposes of procurement planning, transmission planning and distribution planning. So we don't have a lot of history, but what we do have is 2002, 2003 and 2004.

And what you can see, if you're not blocked by me and this podium here, is that on an observed basis we have tended to overforecast for the last couple of years. So if you just looked at our forecast and you looked at what actually occurred, you would see that in 2002 we did under-forecast the load by 626 megawatts. But in 2003 we over-forecasted by 374 megawatts. And in 2004 we over-forecasted by 809 megawatts.

But that's not really a fair comparison because the forecast was done on a certain assumption of temperature. And so to be fair I included the column that says temperature normalized observed where I've attempted to kind of create a history that would be consistent with the temperatures that were in the forecast. And there you can see that the model has come pretty close for the last three years, and we've tended to just under-forecast a bit. So, we were caught a little bit off guard in 2002 by the strength of the return from the energy crisis. And so we did under-forecast load by about 400 megawatts that year. But in 2003 and 2004 we came within a couple hundred megawatts.

But overall I can agree with earlier people who said that in general the year-ahead forecast error for peak load forecasting does tend to be in the range of 3 percent. That's what the statistics say.

ASSOCIATE MEMBER GEESMAN: I'm not

reading the 2004 line correctly then. Can you walk me through the arithmetic?

MR. ASLIN: Sure. We'll go to 2004?

ASSOCIATE MEMBER GEESMAN: Yeah.

MR. ASLIN: Yes, so the forecast that we had for 2004 originally was 24,066 megawatts.

ASSOCIATE MEMBER GEESMAN: Right.

MR. ASLIN: And what we observed was 23,257.

ASSOCIATE MEMBER GEESMAN: So about 800 megawatts less than you'd forecasted?

MR. ASLIN: Yes, that's right; that's what we observed.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. ASLIN: But it was a significantly cooler than normal day that we had that peak load.

ASSOCIATE MEMBER GEESMAN: Right, which means when you normalize that it looks to me like your normalized observed is only 20 megawatts different from your nonadjusted reserve -- or your unadjusted observed megawatts. Twenty-four -- oh, I'm sorry, I've understood my error.

MR. ASLIN: Okay. You had me going for a second.

ASSOCIATE MEMBER GEESMAN: I'm fine.

MR. ASLIN: I would be happy to field any questions on the demand part now, or we could go to the other part of the presentation which was on the resources.

ASSOCIATE MEMBER GEESMAN: Questions on the demand side?

ACTING CHAIRPERSON PFANNENSTIEL: Just one. Rick, have you made any changes to -- this is clearly a new forecast, new forecasting model that you're using. And are you evolving it, or is it pretty much what you originally designed it to be without major changes?

MR. ASLIN: The only major change that we've made to the peak forecasting model since 2002 is, well, we made a couple changes. One, we've incorporated more recent historical data and more recent forecast data on terms of the drivers.

But in terms of the structure of the model, the only significant change that has been made is that we added -- in the beginning we were using the Livermore weather station as the weather station that we used. And then this last time around we used Fresno and Livermore. So that's the only major change. Otherwise, it's fairly straightforward, simple regression model, and it seems to work.

ASSOCIATE MEMBER GEESMAN: And is the coming year the focus of your forecast methodology, or is this the early year in some longer term projection?

MR. ASLIN: Well, one of the advantages of using a regression model instead of a more complicated engineering approach is that you can forecast the entire time horizon with the same model structure.

So I would say for PG&E we're using this forecast for procurement planning, for transmission planning and for distribution planning. So, --

ASSOCIATE MEMBER GEESMAN: So it's the same methodology --

MR. ASLIN: -- it's intermediate, I guess. Yeah, it's the same methodology all the way through, yes.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. ASLIN: Yeah. And the other thing about using regression is that for example in the forecast that I have for 2005 I've been able to incorporate data all the way through September of 2004.

ASSOCIATE MEMBER GEESMAN: Um-hum.

MR. ASLIN: Okay, well, I thank you very much.

ASSOCIATE MEMBER GEESMAN: Why don't we move on then to the supply portion.

(Pause.)

MR. TOM: Good morning. My name is Bill Tom; I'm the Manager of Portfolio Optimization at PG&E. Basically the responsibility I have is the short-term operation outlook for the year.

I would like to start off by saying PG&E apologizes for not preparing and giving out handouts. We did only bring 15 with us, so we decided not to hand them out at all, but have a lottery afterwards for the lucky 15.

But no, all kidding aside, we will provide written comments this Friday. We will attach these slides as part of our comments.

I'd like to start off by saying that PG&E's in general agreement with the CEC's summer outlook. We will have, by summer, 115 percent of our expected -- we will be meeting 115 percent of our expected customer demand this summer.

And we want to emphasize that of the loads in the ISO northern California area we're roughly about 80 percent of that. So one of the things we're going to point out later is that in commenting on the report is that we're only focusing on what we know, and basically it's of our own system and not the remaining munis or LSEs that may happen to be in northern California.

Our own and contracted resources are expected to be fully available this summer. Since PG&E has the bulk of the hydro in our control area, we want to emphasize that we expect an average energy production year this year based on our earliest forecasts that were completed last Friday. We anticipate that we'll be right at average energy production for our hydro system.

And 100 percent of our hydro capacity will be available this summer during to meet peak demands.

MR. ASHUCKIAN: For those of you on the conference call line if you could hit your mute button until the end. If you have questions during the question period you can come back on.

MR. TOM: We've also included demand side programs and energy efficiency programs in our portfolio that have been proven in the past to be effective during periods when they were called upon.

To answer the Commissioner's question about resources that would be contracted for, we do have the Mirant units, otherwise known as the Mirant wrap, in which we have 966 megawatts of capacity at our disposal at Pittsburg and Contra Costa.

And also we are seeking CPUC approval for a contract that we recently executed with Duke for 650 megawatts of Morro Bay capacity. That's Morro Bay Units 3 and 4. Roughly 325 megawatts apiece.

And we're also -- as far as my understanding, we are also continuing negotiations with other merchant companies who own power plants that have plants that may be at risk for retirement, as well.

One thing we would like to emphasize is that in collaboration with the Cal-ISO we have jointly determined that we don't have any local area reliability or deliverability issues other than RMR for this summer.

And finally, in collaboration with the ISO, we have been upgrading our transmission, such as Path 15 and other facilities within our distribution and transmission area to improve and enhance electric system reliability.

ASSOCIATE MEMBER GEESMAN: Have you moved on to Path 26?

MR. TOM: I'm sorry?

ASSOCIATE MEMBER GEESMAN: Have you moved on to consideration of any upgrades to Path 26?

MR. TOM: I'm not -- I guess -- we have firewalls within our organization, so I'm not exactly sure what our transmission people are considering, but I know they have been participating in the ISO workshops for improving and reviewing transmission issues.

ASSOCIATE MEMBER GEESMAN: Thanks.

MR. TOM: Okay. Like Rick has said, we also have been working with the CEC and other agencies that are interested in the summer situation here. And so we appreciate the collaborative effort and the cooperation that the CEC has extended to us in sharing information and working together.

One of the things that we would like to continue our collaborative effort is to continue sharing information with the agencies such as the CEC.

Like I said at the outset, we concur with the agencies' and the ISO's conclusions with regards to reserve margins in northern California for this summer. But there's some minor issues that we do have with the report, itself. And these primarily have to do with consistency with assumptions and methodologies.

We are undergoing the resource adequacy proceedings at the CPUC. And one of the goals that we would like to see out of our collaborative effort is that we are consistent across all state agencies with respect to assumptions and methodologies.

ASSOCIATE MEMBER GEESMAN: Do you see significate variances now?

MR. TOM: No. I think one of the issues that I'm going to get to in a minute is how hydro is treated. For example, in resource adequacy I think they're talking about a one-in-five conditions. And here, as I understand what's being presented here, is there is some derates further beyond dependable capacity, which is derate of capacity that would be available during adverse conditions. So there is that issue there with respect to hydro.

And like I said before, you know, we are only, I guess while we're the biggest player in northern California, there are other LSEs within the area. And one of the questions that we raise with respect to the report is the deration roughly on a statewide basis of 2700 megawatts of hydro from dependable capacity ratings.

And I understand that Mr. Woodward from the CEC will be coming up to address that issue later in this forum. And one of the questions we would like to have answered is, is this all of California? is it just ISO? With respect to WAPA and SMUD leaving, having a different area definition, does that include any of their resources? So, hopefully it will be an issue that could be resolved very quickly.

And finally, one of the things that we think should be considered as part of our resource portfolio is the counting of demand response and energy efficiency programs.

So that concludes our presentation with respect to demand and supply. Open to questions.

ACTING CHAIRPERSON PFANNENSTIEL: Mr. Tom, on your last point about incorporating demand side programs, I take it that's really your portfolio, not in Rick Aslin's? I mean you're looking at that --

MR. TOM: We have in our supply side roughly 600 megawatts of interruptible programs and price, I guess price-based response programs. That's on the resource side.

ACTING CHAIRPERSON PFANNENSTIEL: And you commented that these are programs that you have some experience with and you have confidence in?

MR. TOM: Right. The interruptibles have been called upon in the past, and they responded -- the nonfirm program, they have responded when called upon. And then the price sensitive programs include the California Power Authority's demand reserve partnership.

And that primarily consists of the DWR pumps that are in our control area. And they responded last year when they were called; and historically they have responded during systems of stress.

ACTING CHAIRPERSON PFANNENSTIEL: So that 600 that you have included in your --

MR. TOM: Supply side.

ACTING CHAIRPERSON PFANNENSTIEL: --

supply side. There are a number of other programs, I understand, under development, and maybe even that are actually out there, price-response programs. But they're not included at this point?

MR. TOM: Not at this time. We've only included what we thought were proven programs that have had some operating experience. Programs that -- I think you're referring to the ones that were proposed for amendment to the CPP program in which programs for loads greater than 200 kilowatts to participate in.

ACTING CHAIRPERSON PFANNENSTIEL: Right, there are a lot of meters out there and customers, I believe, either on or heading towards some kind of demand response rates.

MR. TOM: Right. Those programs are not included, at least in this set of resource assumptions that I've presented here.

ACTING CHAIRPERSON PFANNENSTIEL: Do you have any estimate about how many megawatts might be included in that category? Those customers --

MR. TOM: No, I --

ACTING CHAIRPERSON PFANNENSTIEL: -- that have the meters and have the rates?

MR. TOM: No, I don't.

ACTING CHAIRPERSON PFANNENSTIEL: Thank you.

ASSOCIATE MEMBER GEESMAN: So if I recall what Mr. Ashuckian told us, the staff includes the interruptible and demand response programs in the planning reserve calculation, but drops it out of the table showing operating reserved. And you think that the demand response and interruptible programs should be included in both planning and operating reserve calculations?

MR. TOM: Yes.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. ASLIN: Thank you.

MR. ASHUCKIAN: With that we'd like to have John Schumann come up and talk for LADWP. Sorry if I implied that he was with Southern California Edison in the past there.

MR. SCHUMANN: I'm sure Edison would like that, so --

MR. ASHUCKIAN: We'll get your presentation up here, if you'd like.

(Pause.)

MR. ASHUCKIAN: Your presentation didn't have a virus on it, did it?

(Laughter.)

MR. SCHUMANN: We've been accused of a lot of things these days, so -- I have another disk if you'd like to try it.

MR. ASHUCKIAN: I can't even get out of this mode here.

(Pause.)

MR. ASHUCKIAN: Well, --

MR. SCHUMANN: Commissioner, I can work off my handouts. I think you probably have copies of it and we can just go from there.

MR. ASHUCKIAN: Sorry for the technical difficulties.

MR. SCHUMANN: Good morning; my name's John Schumann. I'm Director of System Planning Projects for Los Angeles Department of Water and Power. And I would like to give you this morning a little overview of what our system peak demand looks like for this summer and also what our resources are also going to look like.

From the handout you can see from the first bullet that we, for 2005, our summer peak demand is going to be 5737 with a capacity of 5050 megawatts. We carry approximately 1100 megawatts of reserve in accordance with the WECC criteria.

That leaves us about a 20 percent reserve margin.

Go to the second bullet, if you do the math, I believe there's approximately 250 megawatts worth of excess capacity for this summer. And we were marketing that -- we had marketed that to Southern California Edison. They declined the offer. So we will be marketing that to the rest of the southwest. That would be on a firm basis.

We're also going to market 500 megawatts of recallable, that's out of our reserves, 500 megawatts out of our reserves for this summer. So that's a combined total of 750 megawatts that will be made available to California and the rest of the southwest.

That's a little different than the numbers that are currently in your proceedings that shows us having available 1000 megawatts. So a 250 difference.

We've had a substantial amount of storm issues with our Castaic pumped hydro facility. That's a 1200 megawatt pumped hydro facility. We're currently in a mode of dredging as we speak, to remove a tremendous amount of mud and silt from the forebay area. And when that's done we should

have the units available for this summer. We
don't expect any problems wit the units this
summer.

ASSOCIATE MEMBER GEESMAN: So you would
expect that to be available by July?

MR. SCHUMANN: We expect it to be
available next month.

ASSOCIATE MEMBER GEESMAN: Oh, great.

MR. SCHUMANN: So we're working around
the clock to get that accomplished.

On the next slide --

ASSOCIATE MEMBER GEESMAN: John, let me
go back to the 1000 megawatt comment. That's been
pointed out to us before, and our staff seems to
hang onto that 1000 megawatts. So I think there's
probably a substantive disagreement between them
and your staff. I don't think it's inadvertent.

And I may be wrong on that, but I do
recall Mark raising that to our attention in a
hearing last September. And yet the number has
stayed in our staff's supply/demand balance
tables.

MR. SCHUMANN: We've had discussions.
I'm not sure why it doesn't get changed, but this
is our forecast. The number that we show there,

the 700 number, that is a one-in-ten number. And so that's what we go with for our summers.

We have two planning modes. I think you mentioned the 10- and 20-year planning modes that we do. And then we have a less-than-one-year planning mode. So we have near term to meet our summers for this summer; and then we have a long-term planning process that we engage in. So we cover both bases.

And so the one-in-ten is the number that we expect to see. That's the hot case for the summer.

ASSOCIATE MEMBER GEESMAN: Now, you know there's been a lot of discussion, and it came up again in the Senate hearing in late February, about whether state policy might be too conservative with respect to the IOU reserve margins. The state might be adopting an overly cautious approach that would produce excessive reserve margins.

But I look at your numbers and I don't perceive your customers to be unhappy at all about the magnitude of your reserve margins. How can you explain that you haven't gotten significant customer push-back on that?

MR. SCHUMANN: I think the events that occurred in the 2001 timeframe secured our planning approach that we believe in having all of our -- being self sufficient in our resources and our reserves so that we do not have to go to the market. And we've -- planned somewhere approximately 20 percent reserves.

So that's what our historical numbers have been, and we try to be consistent with that.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. SCHUMANN: My next slide is just -- they're working?

MR. ASHUCKIAN: Yeah.

MR. SCHUMANN: Okay. That just shows you that we are sharing our load forecasts and our resource plans with the Energy Commission Staff to the greatest extent possible. We do have some confidentiality issues that we've raised, and I think we're working through that with staff, and I think we'll all be on the same sheet pretty soon.

The past year we've had strong growth in our system. There was some mention earlier about difference between the one-in-two, the normal load, and the weather-adjusted numbers. Last year we had a load that we projected, a normalized one-in-two load would be 5300. We had a 5400 load. And you normalize the numbers, it came back right within I think it was 5313 and the forecast was 5319. So we're fairly close on our projection on a weather-normalized basis.

On a long-term basis we are growing on our energy basis 1.5 percent. On our peak demand growth we're averaging somewhere about 1.1 percent. The last couple years we've been a little higher than that. But if you look at the, I think the next slide will show that just a long trend.

The dark one is the actual; and the light-colored one is the weatherized -- weather normalized numbers. And you can see we're tracking fairly well. There's some dips. 2001 was a low year for us, but this is contrary to the rest of the state. I think that's why we had a substantial amount of excess capacity in 2001 because we did not have a peak.

ASSOCIATE MEMBER GEESMAN: So this must represent a multiplicity of forecasts that have been developed over the last 40 years?

MR. SCHUMANN: Yes. We update our forecast every year and we do a mid-year check.

But we issue a formal forecast every year. We just did one in January and we published that.

ASSOCIATE MEMBER GEESMAN: Well, you know, you've kind of turned around the convention that I've always applied to our forecasters, and generally forecasters across the board. They're often wrong but never uncertain.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: This graph would suggest that you guys may be uncertain from time to time, but you're never wrong. Is there not more adjustment between what you forecast and what you've actually experienced than at least visually this graph looks to display?

MR. SCHUMANN: Those are the actuals versus what the normalized data on the forecasts are. Our forecasts have been consistently in the -- probably within 2 percent, 1 to 2 percent. In fact, I looked at the numbers, I brought them today. Our energy forecast for the year, as of February, our projection and our actuals are zero percent difference all the way from July through up to February this year. I think that's a quirk, but we are absolutely on target for our energy use for this year, this fiscal year.

I'm not sure if we have a better crystal ball, but that's just what the numbers show.

ASSOCIATE MEMBER GEESMAN: I'm speechless, which is rare.

MR. SCHUMANN: The next one, just show why we're where we are now and why we have excess capacity on our system, is that in 2000 our -- I've said this before to your folks, but we adopted integrated resource plan, and we embarked on a modernization of our facilities, installing peakers. And then we've gone through and changed out our conventional steam turbines to combined cycle facilities. We completed that at Valley April of last year. We completed Haynes this year; it went into service.

And we are forecasting two additional repowerings that we'll be doing, as you can see the dates there, one in 2008, the other one by 2013, which will pretty much complete the modernization of our existing fleet to combined cycle facilities.

The other components of our resource plan includes distributed generation, photovoltaics. We currently have about 8 megawatts of photovoltaics on our system currently. We have fuel cells and microturbines. We also incorporated the DSM, energy efficiency; the slide shows about 155 megawatts since 2001 timeframe.

We've also had transmission upgrades that are in concert with the combined cycles or any other types of facilities that we've had to bring onto our system.

The other one is the, as you know this last December we completed the modernization of the Sylmar DC system. That was put back in service on December 23, 2004, which now will extend the reliability of that facility for the next, you know, 25, 30 years. And creates transfer capability between Salyla, which is up on the Columbia River, to Sylmar, 3100 megawatts.

ASSOCIATE MEMBER GEESMAN: Are you considering any taps to that? We're approached all the time from people on the Nevada side recommending various taps to the DC line.

MR. SCHUMANN: We've had more than a few requests. I won't give you the number. But, you know, any tap into that system of that size, you're talking about just the connection alone, probably $160 million just to make the connection.

So it's not a cheap connection, so you need to have firm resources behind it and firm contracts in order to justify that kind of expenditure.

And we're looking at the reliability. Something like that requires close coordination with the Cal-ISO, with Edison, BPA, ourselves and the other participants in the DC line.

The other items that we have a charge of 20 percent by 2017 for our renewable portfolio standard. We are in the midst of finalizing the EIR, take it to our board probably next month, of a 120 megawatt wind farm. We also have under contract a 40 megawatt biomass facility that's -- biogas, I should say, that's in the development stage.

We're modernizing one of our small hydro plants which is on our aqueduct system; and just to support the numbers that you've heard earlier, we're seeing probably a 10 percent increase in the amount of energy that's coming out of our small hydro system because of the runoff this year. So that equates to us about 50,000 megawatt hours this year.

And we also issued this last September, we're going through a due diligence process with about 15 different responders to get our RPS standard to 13 percent by 2010.

ASSOCIATE MEMBER GEESMAN: When do you envision any public announcements coming from that solicitation?

MR. SCHUMANN: Well, we're going to do that in stages, and we'll probably start releasing those probably within the next month or so.

This goes back, Commissioner, to your first question or comment about the 1000 versus the 750. I think we need to have the staffs get together and figure out why there's a difference.

And there's some other things that without belaboring some points, but there were some other items in there about derates and the size of the units and retirements and those kinds of things that hopefully we'll be able to get those incorporated in your updates.

Going back to closing remarks, we've been a vertically integrated utility since our existence, and we believe we'll stay that way. And that's really helped our planning process. We're able to integrate our transmission or generation and our distribution system to make it highly reliable.

We've been able to identify what needs to be done, what units need to be upgraded, updated and modernized in order to insure a consistent, reliable future for our customers.

Thank you. Any questions?

ACTING CHAIRPERSON PFANNENSTIEL: Mr. Schumann, do you have any demand response programs, interruptible, curtailable programs?

MR. SCHUMANN: We used to have some, but today we have very little. Based on our resources that we have at this point, it's not something we've been activating, so it's been something that's not been pursued.

ACTING CHAIRPERSON PFANNENSTIEL: Back at the graph where you showed the growth in peak demand and you show your forecast and how well your forecast tracked your actauls, do you have any, just an off-the-top-of-the-head sense of what growth you have in your peak demand over that time period?

MR. SCHUMANN: The total time?

ACTING CHAIRPERSON PFANNENSTIEL: Or more recently would be more interesting.

MR. SCHUMANN: Yes, like I said, our peak demand is about 5500 megawatts; we peaked back in 1998 like everyone else, about 5600-and-something. We grow on an average of about 50 to 75 megawatts a year in peak demand.

ACTING CHAIRPERSON PFANNENSTIEL: Thank you.

MR. SCHUMANN: Sure.

ASSOCIATE MEMBER GEESMAN: Thanks, John.

MR. ASHUCKIAN: We just want to mention that we did take a look at the comment from LADWP regarding the difference between interchange flows. And we think that the difference relates to how we define the control area LADWP utility versus the control area.

MR. BROWN: Yeah, I think the majority of the difference that we see is the 710 megawatts that comes out of Intermountain Power down the DC line. Our assumption is it comes down the DC line into L.A., and then flows out from L.A. to the ISO munis.

MR. SCHUMANN: That's actually one of the areas we'd like to talk to them more about, because we get about two-third of that power, and it's an 1800 megawatt facility, and that equates to 1200 for us, which means only about 600 left. So there's a difference in numbers here that we have to get straightened out.

ASSOCIATE MEMBER GEESMAN: Yeah, I think that's highly worthwhile.

MR. ASHUCKIAN: Next, Bob Anderson and Tim Vonder from San Diego Gas and Electric to come up and talk about their materials. And then after that we'll have Gary Schoonyan from Southern Cal Edison.

MR. ANDERSON: Good morning; my name is Rob Anderson with SDG&E, and I'm the Director of Resource Planning.

I'll first address our supply outlook, and then Tim can later answer any of your load forecasting questions.

First of all I'd like to thank the staff for all their effort that they put into this report. Ever since -- when it used to be the utilities serving all of the load in all of their service territories, we used to each be able to create a table like this. But that isn't possible anymore. So I think the staff is uniquely positioned in order to provide us all this kind of information.

We will be filing some written comments later this week. One of those, I think, I'd like to emphasize now, and I think it's similar to PG&E's comment in that we believe demand response deserves a prominent line on this table along with all the other resources. We believe that's going to be a major emphasis in the state in reducing that peak demand with demand response.

There are specific questions out there that can be called on like any other resource, and they should be listed just like any other resource.

ASSOCIATE MEMBER GEESMAN: And you think that that's true not only from a planning reserve standpoint, but from an operating reserve standpoint, as well?

MR. ANDERSON: Yes.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. ANDERSON: So where does San Diego stand? And given that there's a little bit of uncertainty right now in how everyone does their accounting, I'm going to actually give you three different numbers on where San Diego stands for the summer.

First, if we look at our peak load, the load that we will be serving and the resources we currently have under contract to serve our peak load, we are basically right at the 7 percent operating level this year, depending on which forecast and which day, sometimes my guys come back and tell me we might be short an hour or two. But we are basically right about the 7 percent number. And that is looking at our peak load and our resources that we have currently under commitment.

If we look at the coincident peak as to when will we be peaking along with the rest of the state, we will not be at peak the same time the rest of the state is. Using a coincident peak is part of what's being adopted by the PUC in the resource adequacy proceeding, and although we don't have the exact adjustment for SDG&E yet, we believe we're at about 110 to 111 percent reserves when you take a look at what will our peak be when the rest of the state is peaking.

Lastly is our best guess right now in the total resource adequacy accounting number, this one --

ASSOCIATE MEMBER GEESMAN: Before you get to that one, can I ask you, have you done the coincidental peak on an SP-26 basis?

MR. ANDERSON: I honestly don't know

which one my load forecaster gave me at the time.

ASSOCIATE MEMBER GEESMAN: Oh, because I had understood your last comment to be on the statewide --

MR. ANDERSON: Right.

ASSOCIATE MEMBER GEESMAN: -- coincident peak.

MR. ANDERSON: Yeah, I think you're asking what about us and Edison at the same time.

ASSOCIATE MEMBER GEESMAN: Yeah.

MR. ANDERSON: We can double check that number.

ASSOCIATE MEMBER GEESMAN: Okay. Thank you.

MR. ANDERSON: Also, for resource adequacy in the San Diego region right now, San Diego customers pay for about 2000 megawatts of RMR condition 2 units. These are units that aren't committed to serve anyone else in the state. Our customers are basically paying the entire cost of keeping this capacity available in the state to meet the issues within the load pocket.

Under resource adequacy the customers that are paying for that are able to count that as part of the resource adequacy they're meeting. For the load we're serving, if we added that to our numbers we'd actually be at 156 percent reserve margin.

So, for San Diego, what we're currently doing right now is paying for all the capacity we need to serve all of our load, plus a whole bunch of other capacity in the load pocket.

Now, over time we're hoping to eliminate that double accounting, but for this summer that's how things look.

And with that I'd be happy to answer any questions.

ASSOCIATE MEMBER GEESMAN: Questions? Any questions in the audience? Thanks very much.

MR. ANDERSON: Thank you.

DR. VONDER: My name is Tim Vonder. Actually I think what I have to discuss here is on your next agenda item with regard to the history of forecasts.

ASSOCIATE MEMBER GEESMAN: Okay.

DR. VONDER: Shall we do that now, or --

ASSOCIATE MEMBER GEESMAN: Sure thing.

DR. VONDER: -- later? Okay. Give me just a second here.

(Pause.)

DR. VONDER: Okay, what we can take a look at here is on your next agenda item actually you asked us to review our history of forecasts versus actual peak over the years 1999 through 2004.

So we prepared this chart for you to take a look at. And so if we can start at the top you can see that here we have the forecasted year. Our forecast of peak for that year followed by the actual peak that we experienced in that year, and then we have the variance of forecast versus actual. And then like others before me, PG&E for example, and SCE, they talked about their normalized peak value.

And then we have here the variance of -- well, we normalized the actual so that we can compare against our forecast. And then we have the variance of forecast versus the normalized value.

I'd like to note that the forecast values, the forecast is prepared approximately a year prior to the actual event. So, we're forecasting a year ahead.

And as you can see here by just looking

at this chart, we experienced variances -- high variances in the years 2000, 2001. And 2000, 2001 is that crisis period where actual peak demand came in much lower than we had anticipated.

A couple interesting statistics. At the bottom now, if you take a look at mean absolute percentage error, we computed that 1999 through 2004, so those are all of the years including the energy crisis years. And you can see our MAPE or mean absolute percentage error was 7 percent forecast versus actual 2.6 percent on forecast versus normalized.

And then if we exclude the crisis years, I think we can say that those definitely were not normal, if we exclude the crisis years from the analysis and then take into consideration just 1999 and the years 2000 through 2004, you see the statistic improves quite a bit where we get forecast versus actual of 4.4 percent. And then on a weather-normalized basis, and this kind of tells how good your model is, we have a 1.9 percent mean absolute percentage error.

If we take a look at the graph, the graph kind of tells us the same story, only pictorially. And it's kind of nice to look at it in this fashion.

You can see that the forecast is the blue line with the diamonds. And the actual is the red line with the diamonds. I mean, I'm sorry, the weather-normalized is the red line with the diamonds, and the actual is the dotted line.

And so you can see here that in all cases for all six of these years our weather has actually been cooler than normal.

Looking down at the bar chart at the very bottom, the reason we put this here is just so you can see how significant those energy crisis years were in terms of variance from forecast, 2000 and 2001.

And that's our history.

ASSOCIATE MEMBER GEESMAN: You use a regression model?

DR. VONDER: Yes.

ASSOCIATE MEMBER GEESMAN: And do you have a special short-term model that you utilize, or is this just the front end of your five- or ten-year forecast?

DR. VONDER: No, this is our five-year. Well, we use this model going out about five years.

ASSOCIATE MEMBER GEESMAN: Okay, thank you. Other questions?

MR. CANNING: Got a question.

ASSOCIATE MEMBER GEESMAN: Yeah.

MR. CANNING: You said the last six years have included the normal?

DR. VONDER: Um-hum, San Diego.

MR. CANNING: Have you calculated what the probability of that is?

DR. VONDER: No, Art; no, we haven't.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: Let me ask you. I think it was said earlier that the probability of cooler temperature -- let me see if I recall how this was properly framed. I guess it was against the one-in-ten paradigm, that it was much more likely that you would have cooler temperature than hotter. Were you here during the discussion of the weather stations?

DR. VONDER: Yeah, I heard Rick mention that, and that's an interesting analysis. I'll just have to go back and take a look at that.

ASSOCIATE MEMBER GEESMAN: What weather data do you make use of?

DR. VONDER: Well, we use three weather

stations. We use Lindbergh, we use Miramar, and we use El Cajon. And we weight them, we weight them by geography. We weight them like Tom does, for the three days. And we also take into consideration humidity.

ASSOCIATE MEMBER GEESMAN: How do you factor in humidity?

DR. VONDER: We have an algorithm. I can't -- I don't have it here, but it's a rather complex algorithm that brings it in.

ASSOCIATE MEMBER GEESMAN: And were you making adjustments for humidity before last year, or is that something that you just recently have chosen to do?

DR. VONDER: No, we've done it for quite awhile now.

ASSOCIATE MEMBER GEESMAN: Okay. Thank you.

MR. ASHUCKIAN: And finally we'll have Gary Schoonyan come up for Southern California Edison.

MR. SCHOONYAN: Thank you. Gary Schoonyan, Southern California Edison. We will likewise be responding in written form this Friday, and I apologize for not having any overheads or what-have-you. Don't have to worry about the viruses then, or potential for viruses.

A couple of things I'm going to talk about, a little bit on the primarily supply side, the overall composite of that. And then a couple of items on the demand side.

However, Art is going to be presenting at the next panel, and he'll get into a lot of the details associated with demand forecasting. And particularly talk about the weekend situation that he mentioned earlier, as well as the weighted average on the weather differentials between one station versus others.

With regards to the loads and resource projections for this summer, we are over 115 percent on a one-in-two basis. And over 7 percent on an operating basis using the Energy Commission's one-in-ten year forecast.

This does include, in response to a number of questions that Commissioner Pfannenstiel has had with regards to the demand side, it does include the utilization of the demand side programs on both those instances.

Which, for Edison, is a little more significant, I think, than the other utilities.

We have close to 1000 megawatts in existence right now, which is significant. We're also aggressively trying to expand that. The 2020 program for this summer, as well as expansion of our A/C cycling program this summer.

Between those, as well as other energy efficiency efforts, aggressive energy efficiency efforts we have, some estimate for the critical peak pricing, we're looking at an additional 300 to 400 megawatts of demand side on top of what I've already mentioned for this summer.

Denny mentioned the additional 175 megawatts with regards to bringing back two mothballed peakers, so I'm not going to mention that. However, there is another MWD pump loads. We're in discussions with them, and it looks like on the order of an additional 100 megawatts of interruptible load under extreme conditions associated with coordinating with them.

With regards to the demand forecast, I mentioned Art's going to talk the majority on this, but there are a couple of things that percolated up from my perspective. One had to do with the discussion on coincidents. The forecasts were done in a manner which at least appears to me that there wasn't the coincidents of peaks between the San Diego as well as Southern California service territories.

Based on my years in planning and in operations there is a coincidence. There are certain instances when we both peak at the same time. But typically that is not the case. And there needs to be some consideration of coincidence when looking at developing the various adjustments in the forecasts in the region.

The other thing, and this is something that we at Edison aren't really happy to announce, per se, but it is what it is, is we had a -- we will be having, commencing this April, a rather significant rate increase. And it's the whole concept of price elasticity.

In essence, because of primarily increases in natural gas, but there were some other tariff changes and what-have-you, we're looking at a systemwide average of about 5 percent increase in rates. But hitting the residential consumer, particularly the large users in the residential sector, the ones that I believe Tom referred to in coming up with this differential, I mean they really have a significant effect on peak demand. They get hit probably the hardest, because the majority of the increases in the residential sector, if not all of them, are in the tier 3, tier 4 area.

So there is, from our perspective, going to be a significant price elasticity effect on the residential sector in particular as a result of this. Like I say, it wasn't something we're happy to talk about, rate increases. But it is a fact, and it is something that's going to be prevalent this summer.

ASSOCIATE MEMBER GEESMAN: Have you recalculated your demand forecast to reflect that?

MR. SCHOONYAN: No, we have not. And that's pretty much all I have. Just one other observation real quick. I mean it came out during the Senate hearing, when I was listening to that, and it's kind of coming forward today.

It's you have L.A.'s over -- or not over-resourced; I mean they got 120 percent. You got San Diego, when you include the RMR, at about 150 percent. We're at 115 percent. IID indicated they were at 115 percent in late February.

From our perspective the big uncertainty rests with those load-serving entities that are serving direct access customers. I would hope that the Committee, as well as the Commission and the state, gather some additional insight on those load-serving entities and what they're doing to insure that the summer loads are met this summer.

Thank you.

ASSOCIATE MEMBER GEESMAN: I want to make ceratin I understand you correctly. You are joining with both PG&E and San Diego Gas and Electric in saying that the demand response and interruptible programs should be included in both planning reserves and operating reserves calculations, is that right?

MR. SCHOONYAN: That is correct.

ASSOCIATE MEMBER GEESMAN: Okay. Did you have a response or reaction to PG&E's comment about hydro derates?

MR. SCHOONYAN: Well, we have less hydro than PG&E does, and --

ASSOCIATE MEMBER GEESMAN: Right.

MR. SCHOONYAN: -- it's differently situated. Basically our hydro at this time looks like above-average year. Primarily all of our hydro is from Fresno on down, and it's a little different profile. But we're above average year on hydro this year.

ASSOCIATE MEMBER GEESMAN: Okay, so you didn't have any negative reaction --

MR. SCHOONYAN: No.

ASSOCIATE MEMBER GEESMAN: -- on the way the staff has shown it?

MR. SCHOONYAN: No.

ASSOCIATE MEMBER GEESMAN: Okay.

ACTING CHAIRPERSON PFANNENSTIEL: Gary, what do you think the rate impact will be on the tier 2, tier 3 customers?

MR. SCHOONYAN: I'm not an expert on forecasting. I do recall that we had elasticities on the order of .1 to .3. I think it's more closer to a .3. So, --

ACTING CHAIRPERSON PFANNENSTIEL: But I'm sorry, what is the rate, what do you think the rate increase will be for those customers. You said the overall system average would be about 5 percent --

MR. SCHOONYAN: The overall for the residential consumers is 7 percent, I believe. I believe the tier 3, tier 4 is in the 10 percent.

ACTING CHAIRPERSON PFANNENSTIEL: And you mentioned that while you've incorporated the

1000 megawatts of demand response that you currently have, you expect that there might be some additional demand response for the newer programs going forward.

Are those the over 200 kW customers that already have the meters? Is that the group you're talking about?

MR. SCHOONYAN: A portion of it is, is the critical peak pricing, and it's probably the one area that's probably the most uncertain number. It was, we assume anywhere from 50 to I believe 150 megawatts for that component of it.

ACTING CHAIRPERSON PFANNENSTIEL: But you don't have that incorporated in your --

MR. SCHOONYAN: Not presently, --

ACTING CHAIRPERSON PFANNENSTIEL: -- demand response, okay.

MR. SCHOONYAN: -- but it was part of -- I gave you a range of 300 to 400 megawatts of additional.

ACTING CHAIRPERSON PFANNENSTIEL: Right.

MR. SCHOONYAN: It was incorporated in that range.

ACTING CHAIRPERSON PFANNENSTIEL: Thank you.

ASSOCIATE MEMBER GEESMAN: Thanks, Gary.

MR. ASHUCKIAN: Was Art going to say something for Southern California Edison now, or --

MR. CANNING: I'll wait till the next agenda item.

MR. ASHUCKIAN: Okay, well, I think we're there at this point. We've been kind of doing both of them simultaneously.

MR. CANNING: Well, good morning, again. We brought one soft copy -- hard copy handout. It's labeled, CEC one-in-ten simulation results for 2003. It's a long list of temperatures and years.

I apologize; it's just a worksheet that my staff gave me as I ran out the door. It should be titled, SEC analysis of CEC temperature data, because it's our analysis of what Tom has provided us for the data that he used in his analysis.

It's the 54 years, and they're ranked by the highest simulated peak demand for 2003. That's column one, two, three, four.

And then on column five of this is day of week in 2003. So, and the next column is a 1 if it's a weekend and a zero if it's not.

We got enough of these? Okay. Well, the basic thing is if you look at 2003, when Tom picked the hottest day of the year back in 1955, it was September 2nd. So we take the date September 2nd and look at what day of the week is that in 2003. It was a Tuesday. And it was a Thursday in 2004, and will be a Friday in 2005. So it'll be a weekday all three of those years.

I actually don't know what day of the week it was back in 1955, but I meant to look for that, too.

However, as you look down the week, the whole row of 54 dates, the probability says well, there should be about 30 percent of what ought to be weekends. You also have two holidays in the summer, and they have a very big effect, too. They turn that at least a weekday into a weekend. So that's Labor Day and 4th of July.

Now, in the analysis of the 54 different years for 2003 there were 18 weekend days; for 2004 there were 16; and in 2005, 11. If you use my .3 as about an average, there should be about 15 or 16 would be the average. So 2005 actually fewer weekend days for those exact dates.

Now, I don't know that you actually use

these individuals years, or whether you take the probability of two chances out of seven, plus two holidays throughout the summer, or just which way you do it. But, there is a probability that the highest temperature will occur on a weekend or a holiday.

I think in the, from 2000 on I think we had our highest, once on the 4th of July weekend and the next year it was on the Labor Day weekend. So, it does happen.

And actually in 2004 the hottest day by our own measurement was in May. And May, there was a day in May, May 3rd was like 4.5 standard deviations above normal. It was the hottest day of the whole year. But it didn't create a peak, though. And the staff has eliminated that date outside their analysis. That's good.

So we do get Santa Anas that come through southern California that really heat it up. And a week earlier in April another Santa Ana come through and we were 3.5 standard deviations. So those are two of the hottest days of the whole year, late April and early May.

Now, the point of this is just to bring up what I asked Tom earlier, does he adjust the forecast for the weekend effect. And the question I brought to yours is really are we planning for a one-in-ten temperature event or one-in-ten load event.

We have always interpreted it as a one-in-ten load event. That's what we should be planning for. So that would be our point of view definitely. So you should make an adjustment for that.

And as Tom said, you can take, you know, the historical period and only look at weekdays. Or you can use a probablistic adjustment to the forecast. There's several ways of doing it. I think they have, I think, probably fairly close.

That was one point I wanted to make. The other one is, Tom, could you bring your slides up for slide number 12? Do you have that there? The original pitch one-in-ten weather-adjusted methodology.

MR. GORIN: Slide 12?

MR. CANNING: Slide 12 as I counted back, so it should be the SCE peak variability. There we go. I'm going to walk up to there.

I asked San Diego (inaudible) about this. Here's the median, the last two lines of median. I have the -- this is San Diego. How about Edison. Yeah, that's it.

MR. ASHUCKIAN: Art, it's better if you're on a mike.

MR. CANNING: So this is more of curiosity. But let's take a look at it. So, 1998, right there, almost up to what is that, one standard deviation above? One-in-ten, so in '98, excuse my wiggle, that's as close as I can hold it, one-in-ten was 98. But every year since then has been below the mean.

So I asked my staff, what's the problem, look at that. And the first answer they came up with was like one in 10,000. And then they came up with one in, you know, 100,000 or something like that, going forward.

So they said okay, you know, it's a one standard deviation below in one case, and a .5. And so if you multiple these probabilities together it's a very unlikely situation that we would have six in a row below average; and the cumulative probability is at least one in 10,000.

Now, they tell me, Art, you can only say that going forward. That the chance of having six more in a row would be one in 10,000. And you're not supposed to say it that way quite when you look at historical.

But it has happened. Now, we plan on the 30-year average for the forecast, but we still notice that we've have six cool summers, six cool peak days in a row. And so there might have been hotter days, like I said, on weekends or outside the summer, but that's sort of an interesting condition. I just notified my manager that I'm not planning on it, but it is something to note.

Back in the early '50s you had about several of the same sort of conditions. Whereas here, in this period, you got a few going back to normal. And so that sort of waters it down.

Look at here, you got strings way above average. I mean that's -- so we've tried to look, you know, is it el ni¤o, is it the Pacific (indiscernible) oscillation, tried to find reasons for this. And I think the answer is you can sort of explain maybe the weather in terms of the heat for the whole summer. But trying to predict the peak day is just, it just really is random.

We do go to the National Weather Service. They have a NCEP, National Center for Environmental Prediction. And they'll go out six to nine months predicting weather and precipitation for regions. And for the last four summers they've been predicting much hotter than normal centered around Las Vegas or Phoenix, and extending slightly over, into California, but usually by the L.A. basin, their lines cover the United States, the L.A. basin is either in or out, depends on how you look at the coast, you look at the lines.

So, they're predicting that again for this summer. But my own meteorologist has said, well, you know, the central United States, and actually from us all the way swath up through I guess North Dakota, much heavier than normal range.

So this year I think we, I don't know if we've passed the all-time record or not, but we're within a quarter of an inch in L.A. The wetter the soil is the lower the temperatures are usually. And it tends not to bring in certain atmospheric effects that would tend to give us a lot more humidity and bring in the hot weather.

So, -- a little competition with some rock music there --

MR. ASHUCKIAN: Whoever is on the

conference call, if you can hit your mute button, there's feedback coming through.

MR. CANNING: I'll talk over it if you don't mind. I got a loud voice.

(Laughter.)

ASSOCIATE MEMBER GEESMAN: It does provide a nice tempo --

(Laughter.)

MR. CANNING: As I look at my notes I say where am I now. So it is a little distracting.

So, -- your call is important --

(Laughter.)

MR. CANNING: So, going back to that, the fact is we have been through a cool trend the last six years. And whether you want to say that's implied for the future or not, you know, that's a little bit risky.

But that's happened in five, or six years, when the National Center has predicted a warm, very much warmer than normal for the southwest desert and into California, at least through the desert of California.

So we've actually had cool peak days while they've been forecasting, but fairly accurate, it's been a warmer than normal summer. And we're going into a period where there's been heavy rain, which keeps the ground moisture up, which tends to keep the surface temperatures lower. And they tell me it goes -- the Bermuda high doesn't move west as far; a lot of atmospheres -- but, well, it's probably a relatively cool summer but nobody's going to say what the peak will be. It's just that far out.

The other question -- methodology, we use the same basic method that Tom has. Maybe a little more complex or sophisticated. But complex, let's say. But we use five stations or up to ten stations, rather than three or four. But we still use a three-to-eight moving average, weighted somewhat similar to his. We take the humidity effect by looking at minimum temperatures at night, because when the minimum's high that's when the humidity is high.

So, we found that that picks up most of the humidity effect. The trouble with measuring humidity is the best station with historical data is L.A. Civic Center. And yet it's very much impacted by the marine coastal influence. And we really need something inland like Ontario to see what the humidity is there. We haven't got that data yet.

We used to use humidity index. We've tested it; it made some difference in the forecast. What they found was above 35 percent humidity it added load. Below that it didn't matter what it was, it just didn't make any difference.

ASSOCIATE MEMBER GEESMAN: Your comments about number of weather stations, you use as many as ten for some purposes?

MR. CANNING: Sure. Now, it all depends on what you're doing. So I supervise the group that forecasts tomorrow's energy, too. We started off with five weather stations. And because our vendor at that time says, Art, that's all I can get you by 5:30 in the morning. Well, I believed him. I since found out that was, you know, -- they can do as many as they want.

ASSOCIATE MEMBER GEESMAN: I got a paperboy that's the same way.

MR. CANNING: So we started from five. And then was partly to make it more foolproof. So if the data doesn't come in they can call up the guy and get ten numbers over the phone, you know.

It kept simplicity to the system.

So, and along with this I've had a lot of retirements, so I sort of brought back everyone to using the five stations, both long term and short term, until I get through this retirement process and we can go back up.

We have been using up to ten stations when we're weather adjusting past history. A lot of time to work on the analysis. And I think the more the merrier. You weight them by the air conditioners under that region. And I think it does improve the analysis.

I also, in the past, have worked with my substation planners, and they complain I'm only using ten. They've got 40 substations. They really want 40 different weather stations. So, I sort of get -- and they've got 20 or so.

The limit is usually how much stations you have that has data. And then who's going to forecast that. So, those are the issues we've looked at.

We started off picking stations that had hourly recorded data because we thought we were going to build an hourly model. And that limited our choices early on. So we stayed with five or six stations for the day-ahead forecast, and I'm using that for my weather analysis. It might make a little difference, but right now it's a matter of getting everyone trained and on the same track again.

I definitely think that having one station is bad because I think there's just like a lot of large numbers. You're going to get an averaging if you have four or five stations that won't show up if you use one station. And Lindbergh for San Diego is, like we said, right down there on the water.

ASSOCIATE MEMBER GEESMAN: How would you get around, though, the absence of historical data for the inland stations in San Diego?

MR. CANNING: Well, when I'm limited with that, then I'll go back and see how much data there is. I'll do the analysis with 30 years data, so here's 30 years for all the stations. Now if I go back 50 I'm limited; here's what that gives me. And then I have to intuit something.

There are things that go on like Los Angeles Civic Center moved the weather station back in 1999. And if you didn't account for that you've got bogus data.

ASSOCIATE MEMBER GEESMAN: Yeah.

MR. CANNING: It made like 1.5 degree difference. The other thing, and I guess it shows up here, if you -- those were temperatures and not loads, there is no global warming going on on the peak day. It's been -- all announces that the peak day, if there's global warming going on, and I think you may want to accept that, it doesn't seem to affect the peak day temperatures. They're influenced by something else.

What you'd find is maybe the average temperature in the summer is going up, and certainly average, you know, night-time temperatures in winter are going up. But the peak day isn't. So it's not a, as far as we can tell, it's not a global type change affecting the hottest day of summer.

And there are episodes, you can see cooler periods and the warmer periods. And we've gone back and the closest I can find is what I guess the marine biologists call the Pacific deodacatal change. About every 20 years the oceans off of the northern Pacific either warm or cool on the -- we're actually east Pacific. So they talk about eastern Pacific as either warm or cooler than about 4 degrees or 5 degrees than normal. And in 2000 we entered the cool phase, I think. And we had been in a hot phase.

If you go back all the way to the '50s and '60s it doesn't match up with some of these peak day temperatures, so it's not a good predictor.

El ni¤o maybe is, so we had an el ni¤o very strong in 1998 because that was the summer following a very strong el ni¤o. But if you go back to other el ni¤os, it's random. Sometimes we're normal; sometimes we're -- I don't know if we've been cooler than normal on a peak day after a strong el ni¤o, but it's not a predictor.

So we look for what we can and we just use the 30-year average; and a 50-year average, if anything, would probably lower it a little bit. Lower the mean and raise the variance a little bit more.

Let me switch subjects slightly and address one of your other questions, was our forecast accuracy. Similar, I think to San Diego. I went through the '99 on, our forecasts for each year, into the future up to summer 2004.

And we know when we look at any forecast that was made for 2001 or '02 had big errors in it. So, I said, okay, first of all let's just drop those years out of the average. I think San Diego did that, too. And I said, well, I can look at no more years ahead, but really we're looking at 2005, so let me look at the forecast made in the fall of a year for the following summer, or in the spring of the year for the following summer. So we usually make two forecasts a year.

So I was going through those and skipping anything that bleeds over the energy crisis. We under-forecast on a simple average that the hot and the cold overs and unders average out. We were under by about a percent one year ahead. If you look at the absolute error, it was about 2 percent one year ahead. And that's not weather adjusted. That's just the recorded. And we do weather adjust everything; I just didn't get that put together for this.

So I think that's all the questions.

ASSOCIATE MEMBER GEESMAN: Could you make certain that when you guys submit written comments you do give us those forecast numbers, the historical?

MR. CANNING: You just want the percent

error?

ASSOCIATE MEMBER GEESMAN: Yeah.

MR. CANNING: Yeah, that's fine, sure.

ASSOCIATE MEMBER GEESMAN: You use a regression model?

MR. CANNING: Yes.

ASSOCIATE MEMBER GEESMAN: And is that a model designed specifically to provide a short-term forecast? Or is it the early years in a longer term forecast?

MR. CANNING: It's actually the same models. It was developed for long-term forecasting, but we're still using that, setting a target for this summer. And then we'll, for procurement purposes, start looking three and four months ahead and seeing if the short-term models see anything different.

Three months ahead for our short-term models is, I think, pushing it to the max. I don't know that I trust it that much. So, it's part of the long-term forecast.

We have seen on a weather-adjusted basis probably a decline in load factor since the recovery from the energy crisis. And there's nothing on the economic or population trends that's really anything different going on in the last two years than what happened for the previous ten years. All the growth has been out in the warmer areas of the service area, Riverside and Merino Valley and like that. But that's been going on for 20 years.

So our load factor from 1970 -- '69 is the first year we had summer peak. It dropped like crazy from '70 to about '80 as there was more growth going on. And the summer peak overwhelmed the winter peak then.

Then from '80 to about now it's so noisy, the noise covers up any trend. So as people kept moving out to these sites you would think there would have been a continuing downward trend. But you've had efficiencies, you know, appliances and homes, homes have changed size, a lot of other things that intuitively I understand but I don't know how to quantify actually.

But it does look like, since the energy crisis, on a weather-adjusted basis you do notice some slide in the load factor.

ASSOCIATE MEMBER GEESMAN: How much?

MR. CANNING: A point or two. And I think we've assumed it will probably continue to slide for a couple years, but only -- we don't really know what's causing it, other than all these intuitive factors. So it's probably tied to the recovery effort more than anything else.

Anything else?

ASSOCIATE MEMBER GEESMAN: Okay, thank you, Art. Any questions up here? Questions from the audience? Yes, sir, come on up to the microphone.

MR. BODE: Sure, just a quick comment. If you look at the graph where --

ASSOCIATE MEMBER GEESMAN: You're going to have to say it in the microphone otherwise you're not going to be on the transcript.

MR. BODE: If you look at the graph for the peaks for every single year, they show some clear correlation between there. You could probably model that with a -- model and tease out really what the weather would be like. Because it's not completely totally random. And there's different statistical mechanisms that would incorporate that.

ASSOCIATE MEMBER GEESMAN: Tell us who you are?

MR. BODE: My name's Josh Bode; I'm

actually a graduate student over at UC Berkeley. And I've been working on similar issues.

ASSOCIATE MEMBER GEESMAN: Great; thank you. Yeah, I looked there at the late '60s and figured that's the Age of Aquarius effect, and it continued --

(Laughter.)

ASSOCIATE MEMBER GEESMAN: -- on to the '70s quite awhile. I was here then.

Thank you, Art.

MR. CANNING: Thank you.

MR. ASHUCKIAN: We have four additional agenda items, and I don't know if the Committee would prefer to break for lunch or to continue on through.

ASSOCIATE MEMBER GEESMAN: You know, I think we can wrap this up and still not force people to go too hungry.

MR. ASHUCKIAN: Okay.

ASSOCIATE MEMBER GEESMAN: So why don't we just plough through.

MR. ASHUCKIAN: Okay. Next up we have Bruce Kaneshiro from the Public Utilities Commission to talk about the demand response and interruptible programs.

MR. KANESHIRO: Good afternoon; thank you for the opportunity to comment. I'm with the Energy Division at the CPUC. I was asked specifically to comment on table 9, which is in the draft report -- I'll advance the slides to that.

Which essentially shows the breakdown of authorized CPUC interruptible and demand response programs that the utilities currently have in place. And what you see there are estimated megawatts of what these programs can provide currently.

This table, of course, is produced by the CEC Staff. I was asked to provide comments on it. So before I do that, let me back up back to my first slide, because I thought it was important to provide some context here about interruptible programs and demand response programs.

Interruptible programs are generally called reliability-triggered programs; they're typically triggered the day of or hour of when megawatts are needed quickly. Many of them have been in existence for a couple decades now. Particularly known are the nonfirm, what PG&E calls its nonfirm program, or the I6 program that's run by Edison.

We also have direct load control programs which are best known as the AC cycling program.

In 2000/2001, mostly in response to the energy crisis, the PUC authorized several new interruptible programs. But so far to date, participation and interest in these programs has been modest. And I list there just examples of some of the names of the ones that have been added to the mix of programs that offered.

In general, interruptible programs are considered reliable resources, given the lengthy track record, the fact that they've been in existence for 20 years, or at least for the most part, and their design. Customers must reduce contractually specified amounts of demand or they're faced with substantial penalties.

In the case of direct load control, Edison actually controls the load. They can turn off the customers' AC cycling unit.

So because of those designs these programs, for the megawatts produced, are considered fairly reliable for planning purposes.

In 2003 the CPUC, in collaboration with

the CEC, began authorizing new demand response programs. Programs that are different from interruptible or reliability triggered programs. The Energy Action Plan started us out with a call for these types of programs, price-triggered programs, so to speak, that would reduce peak demand from 1500 to 2000 megawatts by 2007.

To get to that goal the Commission authorized specific yearly goals for the utilities to attain. And there you see are the megawatt goals for 2005 for the three IOUs.

Programs that are triggered on the day-ahead basis count toward the attainment of these goals, while interruptible programs do not. And let me explain that a little bit further in my next slide.

On the day-ahead programs I guess a good way of describing the programs we have today for these new demand response programs; essentially participants are given a one-day notice, as opposed to a day-of notice that demand response is needed.

And the three main ones that have come into place, and so three are the voluntary critical peak pricing, demand bidding program and the CPA's demand reserve partnership program.

In January of this year the Commission authorized modifications to these day-ahead programs; authorized new programs, such as my second bullet point there, the 2020 programs. IOU participation and Flex-Your-Power-Now media campaign, these programs, these two, the 2020 and Flex-Your-Power-Now don't have a trigger, though. They essentially just encourage decreased usage, or in the case of 2020, pay for decreased usage. But they're not tied to a particular trigger point like voluntary critical peak pricing.

The purpose of the January 2005 decision was to help move the utilities toward attainment of those megawatt goals that I had on my previous slide, as well as securing additional megawatts for this summer. Thus it did modify some of the interruptible programs in the hope of attracting more participation.

One example of that is Edison's AC cycling units, AC cycling programs, which was mentioned earlier. Tried to increase that, as well.

So, getting to table 9 in the report, and actually table 9 is, what I have on the slide, my sixth slide here, is just a portion of table 9. There's some other megawatts that are listed there on the bottom. I'm just showing the PUC-authorized programs.

My understanding from the CEC Staff is that the purpose of table 9 is to provide a conservative estimate; essentially what are the least amount of interruptible and demand response megawatts that we can expect.

In comparison, the investor-owned utilities provide to the PUC monthly demand response reports that give us updates as to the number of accounts that have signed up, as well as the estimated amount of megawatts that the programs can provide.

And these monthly reports provide numbers that are significantly higher than what table 9 shows. For example, Edison's January 2005 report, they estimated about 1300 megawatts for all of their demand response programs. So, in comparison to the table 9 report, we have 900, as you can see at the bottom for SCE's column, 960. So I'm just pointing this out just to emphasize the difference in the purposes of the table 9 chart, which is again the conservative estimate of what we can expect, get into consideration, performance over the past, so what we know about the programs today versus the purpose of the monthly reports by the utilities, which is to give us a feel for what are the maximum potential megawatts that the programs can give us.

In looking over the methodologies, the underlying methodologies for the megawatts on table 9, I found that the CEC Staff's use of those methodologies were reasonable. I only have a few minor differences in terms of how they calculate it. It's probably less than 100 megawatts. So I didn't think it was a good use of time to walk through each of those differences.

One, just one example, though, I would say is for Edison's demand bidding program. You see it in the second row. There's an estimate of 72 megawatts. I thought that was a bit too optimistic based on how the program performed this past summer, as well as I believe there may be some underlying double-counting of megawatts there with other programs.

So I will be providing all my comments on Friday to the staff, the suggested changes that I might have.

Just the last point that the new programs, especially the CPP and the demand bidding, are difficult to estimate in many cases, or at least in this case right now. You might say it's a best guess estimate as to what these programs can produce.

And the reason for that is we have limited data and experience with these; they're really just out to 2004 summer. And in that summer, the program was actually called only for test purposes. So without a true situation where the program was triggered by its normal triggers, we're left to essentially estimate what the programs can produce. And that's what you see again in table 9 there.

I think that concludes the presentation on table 9, and happy to answer any questions.

ASSOCIATE MEMBER GEESMAN: Questions for Bruce?

ACTING CHAIRPERSON PFANNENSTIEL: Bruce, just a clarification. You talked about the monthly reports the utilities file at the PUC. And you characterize those as maximum potential megawatts.

In what way is it maximum? Do they take

the total load that is being covered by the program and assume all of that response? Or how do they calculate a maximum?

MR. KANESHIRO: It's different for each program. For the interruptibles, for example, since that's the biggest chunk of megawatts you see there, my understanding is they take the amount of megawatts that the customer has indicated they're willing to be dropped down to. And they then take the customer's maximum peak demand. So that's the load drop.

They add all of those up and they assume then that that will be provided. So there's no, you could say, derating of say a customer just chooses not to perform, that's not factored in. It just assumes everyone will provide that high level of load drop when called.

ACTING CHAIRPERSON PFANNENSTIEL: I see, so the table 9 has a significant amount of derating --

MR. KANESHIRO: Yes, that's correct.

ACTING CHAIRPERSON PFANNENSTIEL: And the interruptible programs are triggered by a call on the ISO's part? Is that how the trigger is done?

MR. KANESHIRO: In general that's correct. They are typically triggered when I believe a stage two alert is called. But I believe last summer Edison did trigger its interruptible program because of perhaps some transmission constraint problem.

So I think it depends on your interpretation of the tariff language as to the specific triggers, but generally they are triggered by ISO call.

ACTING CHAIRPERSON PFANNENSTIEL: Well, the customers signing on, I assume they need some clarification of how often they might be triggered and who might do that?

MR. KANESHIRO: That's correct.

ACTING CHAIRPERSON PFANNENSTIEL: And I know there was some discussion about having a separate north and south trigger. In other words, not having to wait for a statewide critical point, but being able to trigger in the south, if that's the case. Has that happened, do you know?

MR. KANESHIRO: Yes, I believe that the utilities, they don't have to wait for a statewide. I think it can be a regional situation where they can trigger these programs. I believe that's currently in place.

ACTING CHAIRPERSON PFANNENSTIEL: Thanks.

ASSOCIATE MEMBER GEESMAN: Other questions for Bruce? Thanks very much, Bruce.

MR. ASHUCKIAN: Jim Woodward here from our staff at the electricity analysis office will give us a brief update on the hydroelectric outlook for California.

MR. WOODWARD: Thank you. Glad to be here and follow up on this program. It's just sort of an after-thought and partly to dampen down concern that hydro forecasts, hydro supplies will be of serious concern, at least within California.

For the first time this century, and for this first time this millennium the production of hydroelectricity energy in California is expected to be above average. Hydro production from California plants has been below average the last four years. And 2001 was a critically dry year both in California and in the Pacific Northwest.

The year 2000 was incredibly close to average in the water supplies in both regions. This year, based on current water conditions, we expect generation from California hydro plants, including Hoover entitlements, will be 105 percent of average.

And that comes from many sources. Let's see, do we have this -- we'll pull up just one chart here that I have, that may be available as a handout. Right there. And can we make that larger here?

(Pause.)

MR. WOODWARD: Well, anyway, this is just one small chart based on the latest available sources from DWR of water runoff. And it's updated every three months or so, starting February 1st. And the high and the low forecasts always diverge.

Here we go. And the median forecast is just about 100 percent of average for 13 rivers, starting with the Pitt River to the north, down to the Kern. And the low water years down here, they always diverge or converge over time leading towards April 1st when the main forecast is done.

It's updated about three times a year. And that was current through March 15th based on actual water conditions. Did not include last weekend's storm; probably added another 5 percent in northern California and elsewhere.

Close that out and see if I can find -- just give us a couple websites. I think what I wanted is this one -- I'm just going to try and get a couple websites. There we go, see if that comes up. We'll bring that up, thank you.

This is northern Sierra current snow pack, just updated today, showing above average conditions. And what's worth noting is that this year, for the first time in four years, the water supplies have flipped compared to the averages.

The last three years the northern parts of the state got much more than their average amounts. This year the southern parts have gotten much more than their average amounts.

It's more obvious in the central California that the pink line is current conditions, all above average. The blue line on top is the record wet year. The brown line at the bottom is the record dry year. Last year shown in green. This is the top bar here is the northern third of the Sierra. Middle third of the Sierra here. And we'll bring it down to the southern third of the Sierra. You can see the pink line is way above average.

And again, this next smooth line is the

mythical average year that we've never had, but an average of 50 different years.

So I think we can get the next snow map that shows it very well.

Sorry for experimenting to do it this way, but -- and if it doesn't work long, or if you want to cut me off, feel free. But this next map may be fairly interesting.

(Pause.)

MR. WOODWARD: It's loading. And, again, the key area of water storage reservoir is the frozen snow up in the Sierra that is well forecast; it's always worth noting there's more cooperation among utilities and agencies the higher up we go in the watershed.

The data's a little more transparent in real time. And I don't know what it is about that, but it's worth thinking snow. And we still have another month of snow, of good delivery in this area.

I don't know if it's going to load or not. It's just slow here. But at least we don't have the music going with this.

I would take this moment to say appreciate the confidential forecasts that come from utilities. Jan Grygier at PG&E shares some insights. He saved me last week from going on a wet campout where I was planning on taking several people out to Knight's Ferry on the lower Stanislaus. They got 2.5 inches of rain.

And there's other interesting hourly data that LADWP has shared, as well, in their system.

It's not going to load. Well, it would just show the snow forecasts look much much better to the south -- oh, here we go. Thank you; that's it.

And I'll just scroll down. You can see in some parts of the state the snow forecasts are below average. In the Klamath River system it's running forecast to be just 50 percent of average. Central Sierra, these are current snow packs as of March 1st data, looks pretty good the farther south you get.

And we have some very large amounts in the southern Sierra. Especially snow pack sites above 9000 feet. This here was, in many ways, for the utilities, an excellent year. We got some very early cold snow packs right around the first of the year. The amount of gas hedging and uncertainty in that regard, that's money and power in the bank in many ways.

And especially the snow lifts above 9000 feet is not subject to an early quick melt so much as say the marginal mid-elevation snow. And I just wanted to bring this up in part, again to highlight the large amount of cooperation among the many agencies.

And Los Angeles DWP does provide the forecast here for Owens and Mono Lake watersheds on the east side, and their runoff looks to be very good. They are one of the few utilities that does not forecast the energy from this runoff. And, again, if Mr. Schumann's still here, I'd say based on those remarkable forecasts of demand, that it would be worth applying your forecasting tools here to the energy forecast from the runoff, as well. Might prove very useful.

ASSOCIATE MEMBER GEESMAN: Probably want to move on to the stockmarket thereafter.

(Laughter.)

MR. WOODWARD: Yes. Well, I'll just close this out and mention a couple other things that this is -- we do look at the Pacific Northwest in many areas. The Columbia River at

The Dalles is forecasting 67 percent of normal in their latest forecast.

The drought is likely to persist in the Idaho and western Montana area. They may be having a significant severe drought, their record year. That's not a big concern to us in terms of either the reliability or the power for meeting our reliability purposes. We expect that the ties will be filled through other sources that are available there, gas-fired generation.

And that's the same story that Avista Power and Idaho Power are telling their customers. It may cost more, but there's adequate supplies there for reliability purposes.

And part of that, too, is just related to this year's weather pattern. That there was a recharge of water in the upper Colorado Basin that had gone through a five-year drought starting in 2000 when they were well above average. This year that drought is on the way down; the latest in for Lake Powell 108 percent of average. It'll take a long time to bring Powell and then Lake Mead back up. But that concern of drought is attenuating.

And it begins a concern up in the Pacific Northwest. So we'll follow that closely.

This year in many respects modeled an el ni¤o year for major southern California water. The most remarkable thing about water is that the current record holder, or the leading site for rain collection to date is in southern California. Usually might be at Honeydew, Garberville, but as of yesterday the site on Santa Ana River at Little Creek had received 94 inches of rain since October 1st.

So it's great to have water there in southern California, but the timing was a little early.

Thank you.

ASSOCIATE MEMBER GEESMAN: Jim, were you in the room during the PG&E's --

MR. WOODWARD: Yes, I was.

ASSOCIATE MEMBER GEESMAN: You heard his remarks about what they felt might be inappropriate derating of their hydro?

MR. WOODWARD: Yes, indeed. And I'll be happy to talk with Mr. Tom about that. We think the chart may have been a little unclear in that much of what's in the non-Cal-ISO area includes about 2200 megawatts or more of hydro supplies that have been taken out from Cal-ISO from Western and Roseville and Redding. Roseville doesn't have any hydro, but we think that that may bring the total back up in the range that you'd expect, in the 10,000 to 11,000 megawatts total statewide for hydro, including the Hoover entitlements. Some of which come into Cal-ISO; some go to LADWP. But it's a statewide resource.

ASSOCIATE MEMBER GEESMAN: Well, I'd encourage you to sit down with them and --

MR. WOODWARD: Will do; happy to.

ASSOCIATE MEMBER GEESMAN: Other questions for Jim?

MR. WOODWARD: Thank you.

ASSOCIATE MEMBER GEESMAN: Thanks very much.

MR. ASHUCKIAN: Next up we have Kevin Woodruff from -- a representative of TURN, to talk about their issues with the outlook.

And then after that we'll basically open it up for questions and discussion from any other interested parties. And we do have Kevin's slide.

MR. WOODRUFF: Thank you, David. Thank you, Commissioners, for holding this session. My name is Kevin Woodruff; I'm a consultant; I'm here representing TURN.

I want to discuss some issues not quite so much related to the summer of 2005 forecast, but for the following years, the immediate following years.

But first I really do want to thank the Commission for holding this session. I've been aware for several months of a lot of concern about the Commissions and the ISO and other parties about summer of 2005 load resource balances.

I had a chance to see some of the early planning documents that were being circulated among various parties. And several months later now, you know, the rest of us have a chance to come and address these issues in an open public forum.

And I frankly found some of those earlier drafts of those initial planning documents had some information in them and some concepts that were -- needed public vetting, or most of them were scrubbed out over the months.

But forums like this should occur much earlier in the process rather than later. And I appreciate the information that's been included. And I think in Mr. Ashuckian's slides or might have been the other fellow that spoke later, about this being an annual process that is it appears like it will be much more open to the public earlier in the game. So, thank you very much.

There's one key issue I wanted to address. I have only one slide, and I think there's some -- the process that we're here today for and the resource adequacy process that is being developed at the Commission is leading to some policy confusion and a disjunction between policy expectations among our state's political and energy policy leaders.

Be really clear, I'll say it again, the PUC's resource adequacy requirement requires all the LSEs, the load-serving entities, that's the investor-owned utilities, that's the energy service providers and, you know, any community choice aggregators that develop, their obligation to provide adequate resources, individually and collectively, is equal to one-in-two normal peak load plus 15 to 17 percent.

And, again, I've characterized this in terms of LSEs' obligations. These will be deliverable resources; they'll be, you know, there's a whole plethora of detail behind this, as you all know. But that's what LSEs' resource obligations are.

The implicit standard that's in the CEC's March 11th report, which appears to suggest should be followed in the summer of 2005, is not one-in-two normal load plus 15 to 17 percent. It is, instead, if you decompose it, one-in-ten hot peak load, a one-in-six high outage scenario, because that's what you get when you have a one standard deviation above is a one-in-six scenario, high risk retirements inputs, plus 7 percent. This standard is much more stringent than the 15 to 17 percent standard.

I think the Commission, everyone in this room ought to think about what is the state going to be doing going forward and saying on one hand, we have an RAR that says 15 to 17 percent over one-in-two peak load; but then get into the year ahead and start expressing great concern that we haven't met this more stringent standard.

There's a very -- the policy disjunction there is, I think people will find very confusing. And I think policymakers are going to find it embarrassing trying to explain why they are saying, you know, saying good things about our situation, given this criteria, and why this says that we're having trouble. There's a really major disjunction between the two.

And rather than just present you with a problem, I'll give you the solution. That is, focus on your planning criteria. That's the one that has decades of practice behind it, successful practice in keeping the lights on.

The other scenario, the one that the LSEs don't have to do, is an extremely tight criteria. No system or local reliability planning that I've done looks at what I call four contingencies or quadruple contingency scenario. They tend to look at maybe one or two contingencies, as opposed to looking at four contingencies all at the same time.

Make no mistake about it, this criteria reflected in the CEC's March 11th report is an extremely tight criteria that has no place consistent planning. It might be an interesting scenario; it may have -- I've seen it doing some archeology on the Commission's website. It's evolved over the last few years with Commission Staff, particularly input from the ISO, and it may have some use somewhere, but it is not the system planning criteria. And it should not be mistaken as such.

I think the Commissions, both Commissions, this Commission and the PUC and the ISO need to come to sort of understanding and clear communication as to what this scenario means.

Because if you're saying it means we have 1800 megawatts and SP-26 to keep the lights on this summer, you're directly contradicting the RAR policy the state has. You're saying we have -- the lights might go out under this scenario this summer, even though we seem to have adequate resources.

Well, that's always going to be the case. You can always stack up a few contingencies to make the lights go out. That's going to be the case every summer.

So I think the Commissions need to come up with some better definition of what this scenario is and what it really means, and what kind of policy implications it has. Because remember, you get inside the -- once you get outside the LSEs' RAR obligations you don't really have many ways to enforce this higher standard without taking some ad hoc means, which probably means going to the IOUs and having them do it.

Now, I'm glad the state has been looking at the summer of 2005, and it should do it every year. And I'm glad to see that they're going to -- you know, that Mr. Calvert wants to look at 2006 like sooner rather than later. I think that's a very important regular routine annual process.

My concern though is not so much with 2006, but with 2007, 2008, and 2009. There's a hole right now in our sort of the vision of the Commissions and the ISO going forward as to those years. The IEPR process that will be dealt with this year will be sent to the Commission for consideration and for the IOUs' long-term plans in 2006. And we'll presumably get a PUC order late next year, possibly directing the IOUs to take some procurement activities.

Well, if you get something in late 2006, you're not looking at bringing resources online in 2007. Certainly not new resources. You're looking at two, three, four years later.

So my question is, we may have with the year-ahead, you know, an annual year-ahead look, combined with the next iteration of the IEPR IOU review of long-term power purchase plans, or procurement plans, excuse me, we have years of 2007 and '08, maybe 2009, that aren't really being very effectively covered.

I find that occurs to me as a kind of distressing hole in the state's look-ahead at looking for new resources. I'd urge the Commissions to think about perhaps the ISO not just to look at next year, but the next two to three years, and see where problems are emerging under this criteria, and perhaps maybe take some ad hoc steps to deal with that. There's still some time to deal with those summers.

Those are my primary comments. I will make the observation, since no one else has, although I know several of us before this meeting, discussed about it, if you actually add up the data in the March 11th report, by he way, and add up firm resources and interruptible load, you do meet firm load in SP-15 under those scenarios.

You're well under your 7 percent ideal operating reserve margin. The firm load is met under the scenario that's presented in the March 11th report. That's a little factoid I like to put out there for your consideration, as well.

Thanks, again. I appreciate your time

and the opportunity to address this. And, again, I hope, as we move into these year-ahead, maybe two, three year-ahead types of analyses, have -- get them out in the public, in a public forum like this sooner rather than later.

Thank you.

ASSOCIATE MEMBER GEESMAN: Questions for Kevin? From the audience?

Kevin, thank you very much.

MR. WOODRUFF: Thank you.

MR. ASHUCKIAN: At this point we have open discussion and comments from any other interested parties. That's the last of our formal agenda items.

ASSOCIATE MEMBER GEESMAN: Okay, it's open mike time. Anybody want to step up? Anybody on the telephone or on the internet that would like to comment?

Well, I thank you all for contributing today. And I look forward to the written comment that are filed. I think that the Senate Committee has done all of us a public service by suggesting that the Commission use its authority to vet some of these planning assumptions.

I think that the staff is not to be

faulted for responding last fall, and in doing so informally. We have divided responsibilities. In many ways we combine the best features of a department structure when we do respond to requests from the Governor's Office in order to plan for contingencies.

Ultimately, though, we are a Commission. And we do have a public obligation to subject our underlying assumptions and planning criteria to public scrutiny. And I am grateful that the Senate has reminded us of that.

I think that Bob Therkelsen had a good idea when he suggested we do this regularly. And certain would be my intention to encourage my colleagues to calendar this as a regular item in the years ahead.

I want to thank you all again. And I look forward to the written comments.

(Whereupon, at 12:30 p.m., the Committee Workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 5th day of April, 2005.